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May 29, 2020

Ms. Karlene Fine
Executive Director
North Dakota Industrial Commission
State Capitol, 10th Floor
600 East Boulevard Avenue
Bismarck, ND 58505-0310

Dear Ms. Fine:

Subject: Final Report Entitled "Integrated Carbon Capture and Storage for North Dakota Ethanol Production – Phase III"; Contract No. R-038-047; EERC Fund 23627

Attached is the final report for the period of December 1, 2018 – May 31, 2020.

If you have any questions, please contact me by phone at (701) 777-5013 or by e-mail at kleroux@undeerc.org.

Sincerely,

Kerryanne Leroux

Digitally signed by Kerryanne Leroux
DN: cn=Kerryanne Leroux, o=UND, ou=EERC, email=kleroux@undeerc.org, c=US
Date: 2020.05.29 15:54:51 -05'00'

Kerryanne M. Leroux
Principal Engineer, Subsurface R&D

KML/kal

Attachment

c/att: Andrea Holl Pfennig, NDIC

INTEGRATED CARBON CAPTURE AND STORAGE FOR NORTH DAKOTA ETHANOL PRODUCTION – PHASE III

Final Report

(for the period of December 1, 2018 – May 31, 2020)

Prepared for:

Karlene Fine
North Dakota Industrial Commission
600 East Boulevard Avenue
State Capitol, 14th Floor
Bismarck, ND 58505-0310

Contract No. R-038-047

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May 2020

EERC DISCLAIMER

DOE DISCLAIMER

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NOMENCLATURE

APD	application of permit to drill
ARB	[California] Air Resources Board
CCS	carbon capture and storage
CFP	[Oregon] Clean Fuels Program
CFR	Code of Federal Regulations
CFS	Clean Fuel Standard
CI	carbon intensity
DAS	distributed acoustic sensing
DBP	[California] Design-Based Pathway
DEQ	[Oregon] Department of Environmental Quality
DIC	dissolved inorganic carbon
DMR	[North Dakota] Department of Mineral Resources
DO	dissolved oxygen
DOE	U.S. Department of Energy
EERC	Energy & Environmental Research Center
gpm	gram per minute
GPS	global positioning system
IRS	Internal Revenue Service
kW	kilowatt
kWh	kilowatt-hour
lb/hour	pound per hour
LCA	life cycle analysis
LCF	low-carbon fuel
LCFS	[California] Low Carbon Fuel Standard
mg/L	milligram per liter
mi^2	square mile
MWh	megawatt hour
NDAC	North Dakota Administrative Code
NDCC	North Dakota Century Code
NDIC	North Dakota Industrial Commission
PDP	process design package
psig	pound per square inch gauge
P/T	pressure/temperature
RTE	Red Trail Energy, LLC
scfh	standard cubic foot per hour
Section 45Q	Enhancement of Carbon Dioxide Sequestration Credit
SFP	[North Dakota CO_2] Storage Facility Permit
SGPS	soil gas profile station
SpC	specific conductance
TDS	total dissolved solids
UIC	underground injection control
μS/cm	microsiemen per centimeter
USDW	underground source of drinking water

INTEGRATED CARBON CAPTURE AND STORAGE FOR NORTH DAKOTA ETHANOL PRODUCTION – PHASE III

EXECUTIVE SUMMARY

The Energy & Environmental Research Center (EERC), in partnership with Red Trail Energy, LLC (RTE), a North Dakota ethanol producer; the North Dakota Industrial Commission (NDIC); and the U.S. Department of Energy (DOE), executed several efforts to advance carbon capture and storage (CCS) implementation for the RTE case study. The project technical team comprised the EERC, RTE, and Trimeric Corporation. Specific outcomes included 1) a process design package produced for CO_2 capture integrated with North Dakota ethanol production, 2) baseline monitoring and characterization data required for geologic CO_2 storage permits, 3) a template for a North Dakota CO_2 storage facility permit (SFP) application, 4) an implementation plan to satisfy the requirements of North Dakota regulations as well as out-of-state low-carbon fuel markets and/or other incentive programs, and 5) CCS outreach for stakeholders and western North Dakota communities. The RTE CCS effort provides a road map toward successful integration of commercial-scale CCS with small-scale industrial fuel production in North Dakota.

Process designs were generated to provide the foundation for a formal engineering design of a CO_2 capture system at a small industrial fuel facility. Vendor bids were acquired for a CO_2 liquefaction facility to process a fermentation-generated CO_2 stream from the RTE ethanol facility. The estimated installed cost for the CO_2 liquefaction facility is $19,800,000, which includes an estimated $10,700,000 to purchase facility equipment and an estimated $9,100,000 for installation, storage tanks, and freight. The CO_2 Capture Process Design Package summarizes these findings for the RTE CCS case study.

Monitoring for key indicators specific to groundwater and soil gas chemistries provides an effective means of complying with permit requirements for long-term monitoring of near-surface environments. Therefore, near-surface environments were characterized in May, August, and November 2019 to define natural seasonal variability within the RTE CCS study area. Sampling and analyses were conducted to determine existing shallow groundwater and soil gas chemistries in the study region. The characterization of near-surface environments is being used to inform the development of monitoring protocols that comply with North Dakota CO_2 SFP requirements. The results generated will help establish the required 1-year baseline monitoring of near-surface conditions and inform development of the required long-term monitoring program.

A 3D seismic survey was acquired in March 2019 over ~8 square miles in the RTE CCS study area. Interpreted results estimated 3000 feet of confining zone between the Broom Creek Formation (storage target) and the lowermost underground source of drinking water (Fox Hills Formation) and that the thickness of the Broom Creek injection target varies 230–420 feet within the survey area. Results informed the location of a planned stratigraphic test well and associated characterization program. No impediments were identified that would prevent the project from moving forward. A stratigraphic test well is the recommended next step to acquire the remaining data necessary to qualify the site for CCS and develop a North Dakota CO_2 SFP application.

RTE obtained a permit to drill, approved by NDIC on December 2, 2019, for a stratigraphic test well which is part of a critical path to achieving an underground injection control (UIC) Class VI compliance. Several recommended practices resulted from the permit process, including collection and analysis of geologic core through the CO_2 storage zone and a minimum of 50 feet in the overlying and underlying confining zones. This led to development of downhole testing/logging and coring programs that are compliant with North Dakota CO_2 SFP requirements. A North Dakota Geologic CO_2 Storage Permits Template was created for industrial projects, including a) permit to drill a stratigraphic test well, compliant with UIC Class VI data requirements, and b) CO_2 SFP.

California, Oregon, the Internal Revenue Service (IRS), and other entities continued to mature incentive programs in 2019–2020, providing more substantive economic opportunities for CCS implementation at small-scale fuel production facilities. The California Air Resources Board (ARB) officially adopted a CCS Protocol under its Low-Carbon Fuel Standard (LCFS) Program in January 2019, providing an opportunity to submit a Design-Based Pathway (DBP) application for an approved temporary (not certified) carbon intensity value. The DBP provides confidence to progress the project and supports investment for facility design. Oregon's Clean Fuels Program incorporated CCS verbiage in its proposed draft rule changes, released in December 2019 for potential adoption in 2020. Additional entities (e.g., Washington, Colorado, Canada) have proposed legislation or feasibility studies to inform potential development of LCF programs for their regions. The IRS released a request for comments in May 2019 pertaining to guidance and clarifications for the Enhancement of Carbon Dioxide Sequestration Credit (a.k.a. Section 45Q) tax program that, when addressed, may increase confidence and certainty for new applicants.

Frequent outreach activities were conducted to generate positive engagement with stakeholders and communities regarding CCS integration with North Dakota ethanol fuel production. No substantive opposition to the project was encountered. Events and materials included community open houses with posters and hands-on displays, city and county commission meetings with informational packets, and project activity-focused fact sheets for all events and landowners; public website access was also provided. A Public Outreach Package for CCS in North Dakota was compiled to serve as a guidebook for CCS efforts in North Dakota rural communities.

The results of Phase III allowed project partners to move closer to implementing the first integrated ethanol–CCS effort in North Dakota in order to capitalize on evolving incentive programs. RTE received approval of an LCFS DBP from California ARB on February 28, 2020, for potential ethanol–CCS. RTE completed drilling a stratigraphic test well in April 2020, providing downhole data at the site to 1) develop a North Dakota CO_2 SFP application, 2) finalize the CO_2 liquefaction facility design, and 3) develop a certification application under the LCFS CCS Protocol. The RTE CCS case study is demonstrating how small-scale commercial CO_2 emitters might economically implement and operate CCS infrastructure and engage in the CCS industry in North Dakota.

The authors would like to thank Computer Modelling Group Ltd. (CMG), ESRI, IHS, Neuralog, and Schlumberger for allowing the use of their software packages in support of this work.

INTEGRATED CARBON CAPTURE AND STORAGE FOR NORTH DAKOTA ETHANOL PRODUCTION – PHASE III

INTRODUCTION AND BACKGROUND

The Energy & Environmental Research Center (EERC), in partnership with Red Trail Energy, LLC (RTE), a North Dakota ethanol producer; the North Dakota Industrial Commission (NDIC); and the U.S. Department of Energy (DOE), completed several activities which advanced the RTE carbon capture and storage (CCS) case study further toward implementation. CCS is the process of capturing CO_2 from industrial sources and injecting it into geologic formations, deep underground, for permanent, secure storage. Figure 1 provides a simplified block diagram of the CCS process at an ethanol plant.

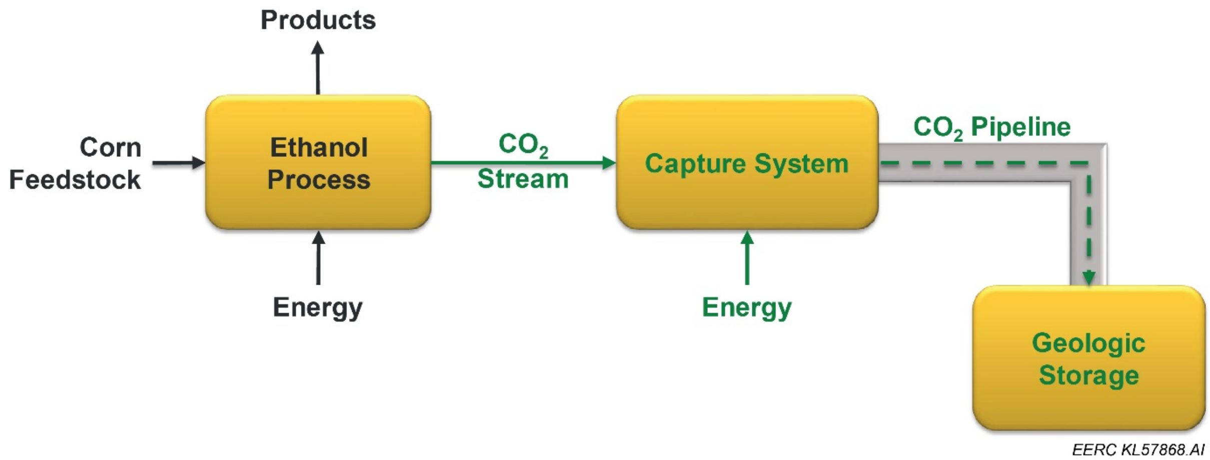

Figure 1. Block diagram of ethanol–CCS process.

In addition to the EERC and RTE, the project technical team included Trimeric Corporation, a firm of chemical process engineers with established expertise in large CO_2 purification and compression facilities. Investigations continue to support a CCS business case for reducing the carbon intensity (CI) of fuel production at the RTE facility. The RTE CCS study region is located approximately a half mile southeast of Richardton in eastern Stark County, North Dakota (Figure 2).

The RTE CCS site provides an ideal opportunity to examine the commercial deployment of CCS integrated with ethanol production. The site overlies geologic formations that have the potential to store CO_2 emissions generated by the RTE ethanol facility for decades. The facility generates about 180,000 tonnes of CO_2 annually from the fermentation process during ethanol production. The Broom Creek Formation underlies RTE's facility at a depth of approximately 6400 feet, with an estimated 3000 feet of confining layers between formation and surface (Leroux and others, 2017). Over a period of 20 years, the RTE CCS effort could store approximately 3.6 million tonnes of CO_2.

The objective of Phase III was to advance implementation of CCS at a small-scale commercial ethanol facility. Activities completed in Phase III included 1) developing a process design package for CO_2 capture integrated with North Dakota ethanol production, 2) collecting baseline monitoring and characterization data required for permit applications, 3) creating provisional North Dakota permit applications for geologic CO_2 storage, 4) evaluating potential integration of North Dakota regulations with out-of-state low-carbon fuel (LCF) markets and other incentive programs, and 5) conducting outreach regarding CCS targeted to rural western North Dakota communities.

With NDIC and DOE funding support using the RTE facility as a case study, the EERC assessed the technical and economic prefeasibility of integrating CCS with ethanol production (Phase I; Leroux and others, 2017) and resolved uncertainties related to regulatory, processing, and financial stipulations (Phase II; Leroux and others, 2018a). The Phase III project initiated field research plans developed during Phases I and II. Collectively, Phases I–III have significantly improved understanding of the technical and nontechnical challenges associated with implementing CCS with small-scale CO_2 industrial emissions.

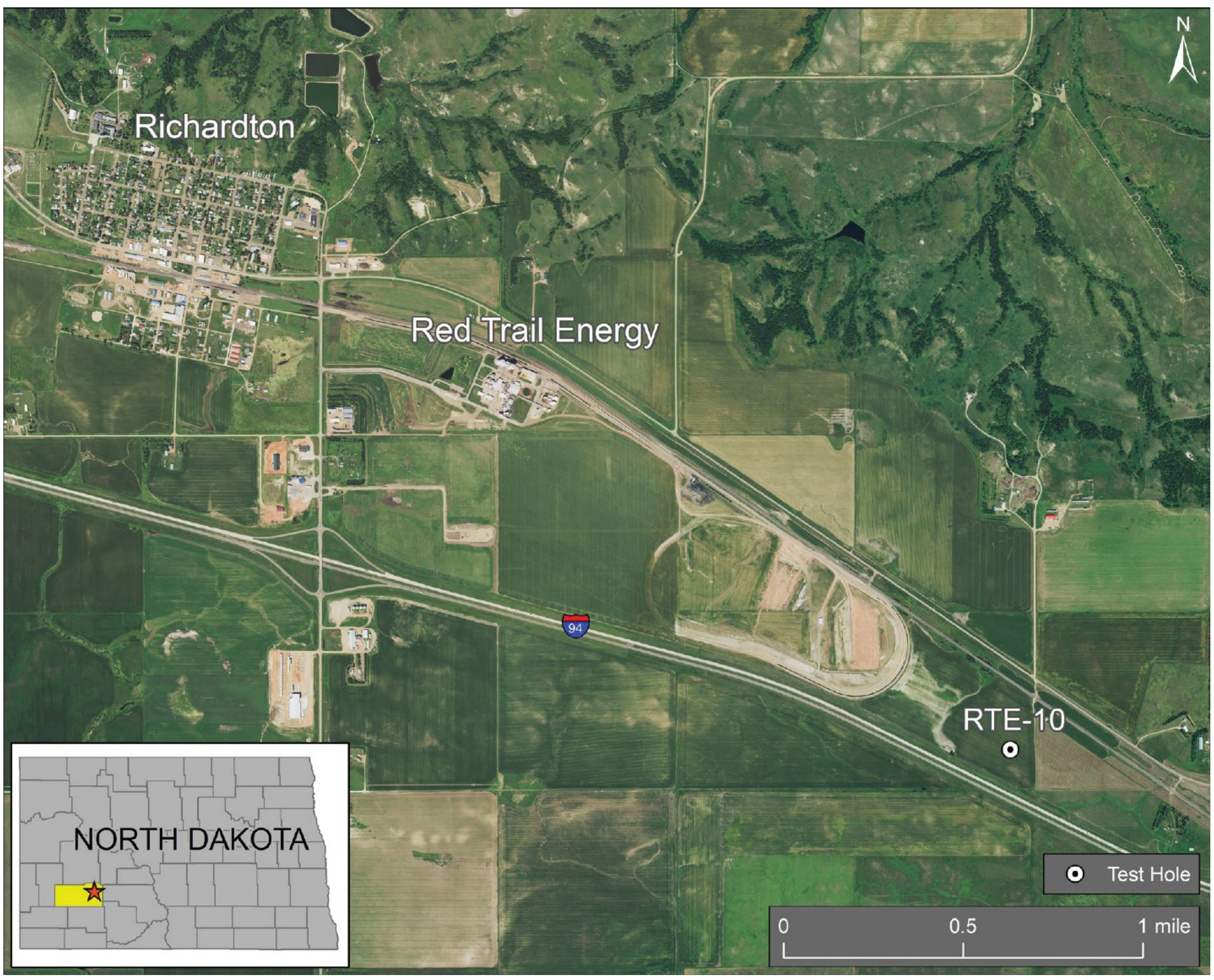

Figure 2. RTE CCS case study site.

CO_2 CAPTURE PROCESS DESIGN

Process designs were generated to provide the foundation for an engineering design of a CO_2 capture system at the RTE ethanol facility. Vendor bids were acquired for a CO_2 liquefaction facility to process a fermentation-generated CO_2 stream from the North Dakota ethanol plant. The estimated installed cost for a CO_2 liquefaction facility specific to RTE is $19,800,000, which includes an estimated $10,700,000 to purchase facility equipment and an estimated $9,100,000 for installation, storage tanks, and freight. The CO_2 Capture Process Design Package (PDP; Piggott and Vance, 2019; Appendix A) summarizes the CO_2 liquefaction facility specifications.

Processing CO_2 from the RTE Ethanol Plant

Process designs were developed for a CO_2 liquefaction facility that integrates with the existing processes at the RTE ethanol plant. The PDP (Appendix A) includes process flow diagrams, basic piping and instrumentation diagrams, and a preliminary layout for the RTE facility. The liquefaction facility design is rated to process 600 tonnes/day CO_2. A small vent (≤0.5% CO_2 stream) from the distillation column to purge noncondensable gases is the only emission in the current design.

The liquefaction facility (Figure 3) was designed to capture the CO_2 currently produced during RTE's fermentation process (following the scrubber prior to stack emission, Figure 4), compress the gaseous CO_2 stream to approximately 350 psig, dehydrate the stream, and then liquefy the CO_2 using a closed-loop ammonia (NH_3) refrigeration process. A conventional distillation column would distill the liquid CO_2 to remove oxygen in addition to other

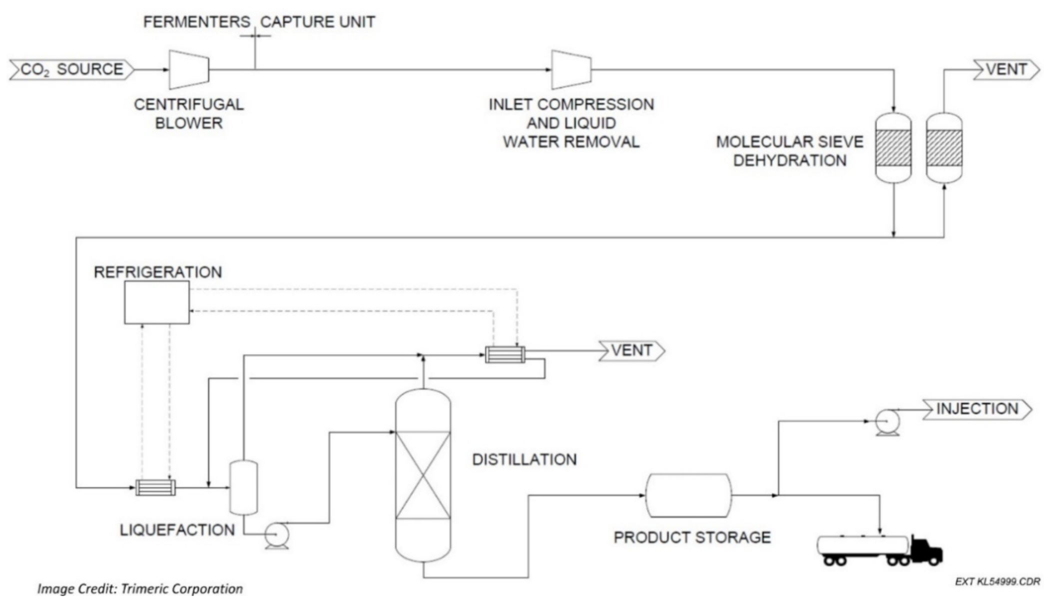

Figure 3. Example CO_2 liquefaction processing facility (Leroux and others, 2018).

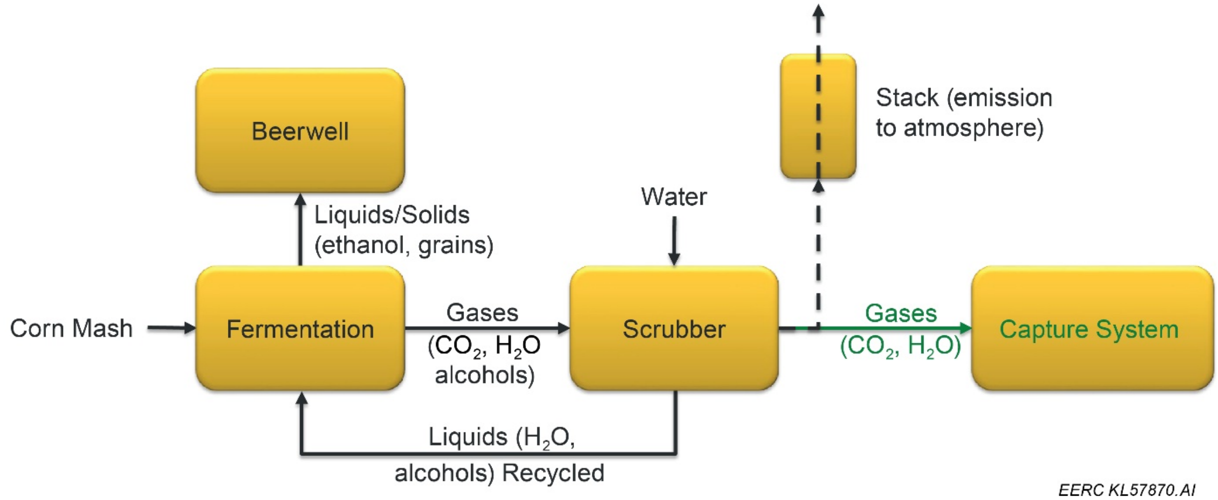

Figure 4. Block diagram of partial ethanol capture process.

noncondensable gases. Liquid CO_2 product from the distillation column would then flow 1) directly to a pipeline on RTE property for geologic injection and storage or 2) to storage tanks for truck loading for sales.

Vendor Response

Bids for a CO_2 liquefaction facility were acquired from three different equipment-manufacturing firms with specific design and build experience in such facilities. Rated to process a maximum of about 700 tonnes/day of CO_2, ±10% accuracy proposals were provided.

Table 1 provides a breakdown of major components for the CO_2 liquefaction facility. The estimated total cost of the facility is $19,800,000. The estimate includes an average purchased equipment cost of $10,700,000. Freight and installation costs are estimated to be $6,500,000, and storage tanks for liquefied CO_2 product are estimated at $2,600,000 installed, providing a sales option for the captured CO_2.

Table 1. Average Estimated Capital Cost for Liquefaction Facility Integration at RTE Site

Item	Cost
Purchased Equipment	$10,700,000
Equipment Installation	$6,300,000
Freight	$200,000
Storage Tanks (installed)	$2,600,000
Total Installed Equipment	**$19,800,000**

Estimated utilities required for a 700-tonne/day CO_2 liquefaction facility at RTE include electricity, cooling water, wastewater disposal, makeup water, and instrument air (Table 2). A significant portion of the required electricity is attributed to compression of the feed gas and the refrigerant system. Electrical load for the liquefaction facility is estimated to be 150 kWh/tonne, with a power demand of 3760 kW. The cost–benefit of contracting additional power with the current electrical provider compared to installing a cogeneration system to cover increased energy needs is being evaluated.

Table 2. Utilities/Demand Estimates for Liquefaction Facility at RTE Site

Utility	Consumption
Electricity	3760 kW
Cooling Water Circulation	3610 gpm
Wastewater	10 gpm
Makeup Water	60 gpm
Steam (125 psig)	1160 lb/hr
Instrument Air	1760 scfh

Cooling water will require addition of a tower cell to the existing cooling water system at the RTE ethanol plant (included in the Table 1 cost estimate) in order to accommodate 3610 gpm in additional circulated cooling. Instrument air requirements of 1760 scfh (e.g., valves, etc.) can be accomplished by existing systems. The additional 1160 lb/hr steam required can be accommodated by existing natural gas boilers at the plant. Wastewater and makeup water requirements are nominal (10 and 60 gpm, respectively), which can be accommodated through existing systems.

Discussion

Opportunities to optimize the capital and operating cost of the liquefaction facility may be further investigated. This includes postponed installation of storage tanks for future liquid CO_2 market options. In addition, improved efficiencies of the CO_2 product heater and the NH_3 condenser (see Appendix A process flow diagrams) may be possible, albeit with operational and investment considerations.

CO_2 Storage Tanks. Provisions in equipment layout must be made if it is decided to postpone installation of storage tanks yet maintain the option to add them later. Storage tanks can also provide a buffer between liquefaction and injection should the liquefaction facility be shut down for short periods.

CO_2 Product Heater. The facility design includes a heater that uses utility steam from existing infrastructure to heat the high-pressure liquid CO_2 prior to geologic injection. Alternatively, liquid NH_3 could be used instead (from the NH_3 receiver), reducing steam consumption. This routing would subcool the liquid NH_3, increasing the efficiency of the refrigeration system. A drawback to using a liquid NH_3 system is that if the liquefaction facility is offline, geologic injection would stop (i.e., negating an advantage of buffer storage).

NH_3 Condenser. A wet surface air cooler design for the NH_3 condenser would reduce utility demand by ~20 kWh/tonne CO_2 but require an additional $400,000 capital investment. A wet surface air cooler is a hybrid cooling tower design using both air and water to maximize cooling and minimize operating costs. This design reduces the condensation temperature of the NH_3, reducing power requirements. The operating cost reduction will depend on utility costs, a difference of about 3600 MWh/yr for the RTE CCS case study.

NEAR-SURFACE MONITORING

Baseline monitoring of near-surface environments, conducted in May, August, and November 2019, defined the natural seasonal variability in groundwater and soil gas ecosystems within the RTE CCS study area (Figure 2). Part of the site characterization program for CCS implementation, sampling and subsequent analyses were conducted to determine the existing shallow groundwater and soil gas chemistries in the study region. The characterization of the near-surface environment informs the development of monitoring protocols that comply with North Dakota CO_2 storage facility permit (SFP) requirements (see North Dakota Drilling and CO_2 Storage Permits section). The results generated will help establish the required 1-year baseline monitoring of near-surface conditions and inform development of the required long-term monitoring program.

Numerous assessments have shown tremendous variability within near-surface environments corresponding to temperature, moisture, and land use trends; biologic activity; and system perturbations (Leroux and others, 2018b; Gal and others, 2013; Romanak and others, 2012; Yang, 2011). Several key indicators linked to chemical and biological processes provided a strong chemical response during exposure laboratory tests to low CO_2 concentrations. When evaluated in combination, these indicators offer an effective means of complying with North Dakota CO_2 SFP requirements. The indicators were specific to groundwater and soil gas measurement, all of which can be easily and accurately measured using field and laboratory techniques. Groundwater indicators included a sudden significant drop of pH coupled with a doubling of alkalinity and increase in specific conductance (Leroux and others, 2018b). Soil gas indicators included a significant deviation from oxygen, CO_2, and nitrogen ratios coupled with process-based indicators, described further in the following sections (Leroux and others, 2018b; Romanak, 2012). The same key indicators are to be expected at the RTE CCS site; thus the previous assessments provided a guide to site selection, sampling protocols (described in Appendix B), and selection of baseline parameters to be monitored.

In addition, naturally occurring isotopes can serve as potential tracers for tracking injected/stored CO_2 based on the premise that the isotopic composition of both injected CO_2 (e.g., generated via the corn fermentation process at the RTE CCS site) and the storage formation water (into which the CO_2 is injected) will be different from the isotopic composition in underground sources of drinking water (USDWs) directly above. Key indicators using isotopes would therefore be a significant deviation from baseline measurements. CO_2 from corn ethanol production typically generates a carbon isotopic composition (δC^{13}) signature ranging −16‰ to −12‰ (O'Leary, 1988). Therefore, isotopic analyses for groundwater and soil gas focused on investigating $\delta^{13}C$ as a potential indicator for use in long-term monitoring for the RTE CCS study region.

Groundwater Sampling

Existing groundwater wells were identified using data registered with the North Dakota State Water Commission (2019). Of the 26 wells identified within the RTE CCS study area, many are shallow (<300 feet) or found to be no longer operational based on direct communication with well owners. Because many residents of Richardton obtain drinking water from the Southwest Water Authority pipeline, which sources water from Lake Sakakawea in southwestern North Dakota, private wells are decommissioned, thus limiting availability to groundwater sampling in the area. Well selection was narrowed to three private domestic wells with depths ranging 435–1800 feet, with only one completed to the lowest USDW (required for monitoring by the North Dakota CO_2 SFP).

Water quality parameters were measured both in the field and in the laboratory. Water samples from the three wells were collected, preserved, and analyzed for composition and select isotopes to establish baseline geochemical properties for each well. Field measurements of pH, temperature, dissolved oxygen (DO), specific conductance (SpC), and calculated total dissolved solids (TDS) were made using a YSI Professional Plus handheld meter (Figure 5). Field measurements of dissolved CO_2, alkalinity as $CaCO_3$, and chloride were measured using colorimetric titration with a Hanna field test kit. Field instrumentation and laboratory analyses lists are detailed in Appendix B.

Key groundwater indicators that require a minimum of 1 year of seasonal baseline data for effective long-term monitoring are 1) pH coupled with 2) alkalinity and/or 3) SpC to identify what might be a significant change in future results (Leroux and others, 2018b; Gal and others, 2013). All groundwater-sampling results in the study region were alkaline and demonstrated consistent baseline conditions with some seasonal variation: pH averaged ~8.3 ± 0.2, alkalinity averaged ~1300 ± 300 mg/L, and SpC averaged ~2200 ± 500 μS/cm. Dissolved CO_2 was measured for each groundwater sample collection, with all results indicating levels below the detectable limit of 1 mg/L. Results of all compositional parameters analyzed are provided in Appendix B.

Soil Gas Sampling

Site reconnaissance activities identified potential soil gas-sampling locations within the RTE CCS study region, based on potential injection well locations and sampling access from a driveway/road. Eleven sampling locations were selected after locating buried utilities: six on RTE property and five on private land. Global positioning system (GPS) coordinates ensured accuracy for repeat sampling. Several relatively large rainfall events prevented site access to select sample locations during each sampling campaign.

Soil gas samples were analyzed using field meters, collected, and then sent to the laboratory for compositional and select isotope analyses. Field parameters including CO_2, total volatile

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Figure 5. EERC personnel collecting a water sample field reading in August 2019 in the RTE CCS study region, near Richardton, North Dakota.

organic compounds, and oxygen (O_2) were measured using a RAE System PGM-54 handheld multigas meter. Soil gas samples were collected at approximately 3.5 feet deep using a portable hand-driven probe (Figure 6). Two samples were collected at each site for laboratory analyses: a) one in a Tedlar® foil bag for analyses by gas chromatograph at the EERC and b) one in an IsoBag® for isotope analyses by mass spectrometer. Field instrumentation and laboratory analyses are detailed in Appendix B.

Key soil gas indicators that require a minimum of 1 year of seasonal baseline data for effective long-term monitoring in the near-surface environment are 1) CO_2 levels coupled with 2) O_2 levels and/or 3) nitrogen (N_2) as well as 4) process-based assessments to identify what might be a significant deviation in future results (Leroux and others, 2018b; Romanak and others, 2012). Soil gas-sampling results in the study region averaged 0.7% CO_2, 20% O_2, and 79% N_2. Natural environmental seasonal variability was apparent with higher average CO_2 values in the warmer month of August showing soil gas composition up to 7% CO_2. Results of all compositional parameters analyzed are provided in Appendix B.

These sampling parameters also allow the use of a process-based approach for further evaluating significantly deviant CO_2 results from baseline data regarding near-surface soil gas sampling as part of a long-term monitoring program. Figure 7 illustrates the process-based

Figure 6. EERC personnel collect a soil gas sample in May 2019 in the RTE CCS study region for field readings and laboratory analyses.

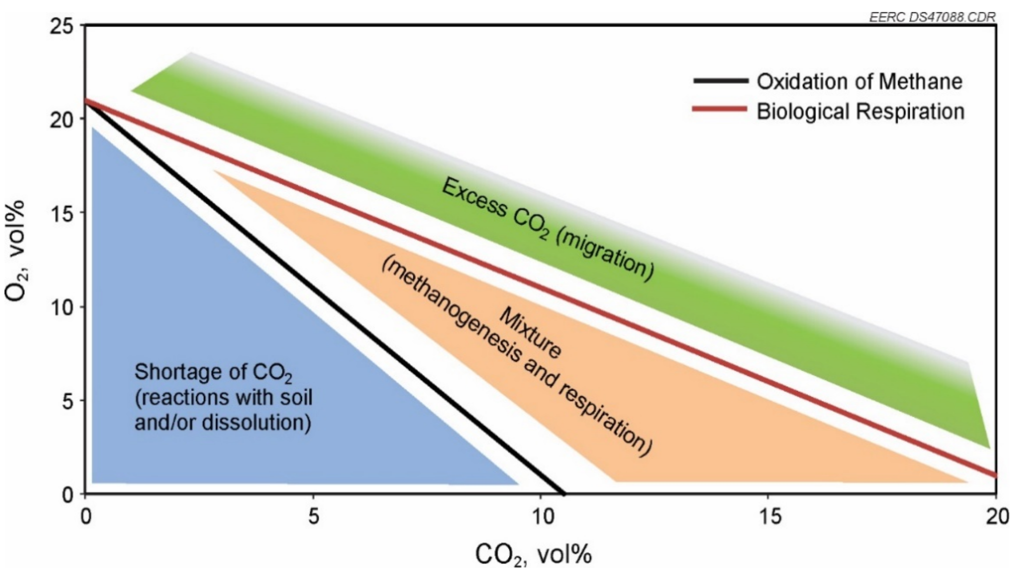

Figure 7. Process-based analytical method for monitoring soil gas concentrations of CO_2 and O_2 (Romanak and others, 2012).

approach which has been proven to alleviate several challenges caused by using CO_2 concentration-based techniques; for example, 1 year of baseline sampling cannot completely account for natural CO_2 variability from climatic, land use, and ecosystem variations over the lifetime (e.g., decades or centuries) of a geologic CO_2 storage effort (Romanak and others, 2012). Natural levels of soil gas CO_2 resulting from the aerobic microbial oxidation of organic matter are represented in simple terms by Equation 1, where 1 mole of oxygen produces 1 mole of CO_2 and plots with a slope of −1 on a graph of O_2 versus CO_2 (the red line on Figure 7). Methane (CH_4)

may be produced under anaerobic soil conditions. The oxidation of CH_4 can be another source of natural CO_2 and is represented by Equation 2, where 2 moles of oxygen produce 1 mole of CO_2 and plots with a slope of −0.5 on a graph of O_2 versus CO_2 (the black line in Figure 7).

$$CH_2O + O_2 \rightarrow CO_2 + H_2O \qquad \text{[Eq. 1]}$$

$$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O \qquad \text{[Eq. 2]}$$

Therefore, soil gas O_2 and CO_2 data plotting on or below the red line (biological respiration) would be indicative of natural biological processes. Those same data that plot above the red line could be indicative of excess CO_2 in the natural ecosystem, a potential trigger or marker for further investigation.

Isotopes as a Monitoring Option

Isotopes can also serve as key indicators to be included for effective long-term monitoring in the near-surface environment, such as carbon isotopic composition (δC^{13}). The groundwater-sampling results demonstrated consistent baseline conditions carbon isotopic composition of dissolved inorganic carbon (DIC, $\delta^{13}C$), averaging about−7 ± 2‰ $\delta^{13}C$ from all three sampling locations in the RTE CCS study region. From soil gas sampling at 11 locations within the RTE CCS study region, carbon isotopic composition of CO_2 (δC^{13}) results varied, averaging −23 ± 2‰. Results of all isotope parameters analyzed are provided in Appendix B.

A process- or relativity-based approach for further evaluating future isotope results from baseline data can be implemented as well. For soil gas, the larger negative $\delta^{13}C$ values suggest that the soil gas CO_2 is sourced generally from C_3 plants, typically ranging −33‰ to −23‰ (Figure 8;

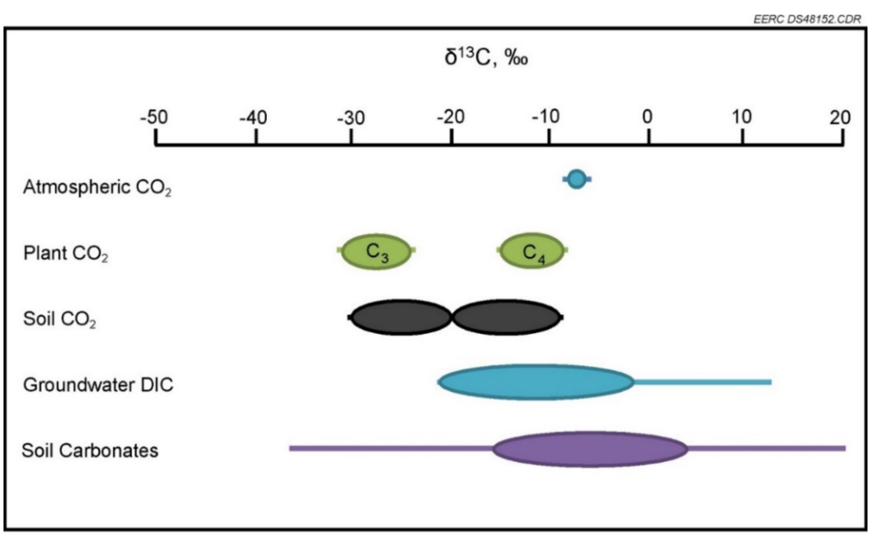

Figure 8. Plot of the variation in ^{13}C fractionation observed in various components of the near-surface environment. Plants with a C_3 metabolism make up the vast majority of plant species alive in the world today and produce isotopic signatures readily observed in soil gas samples (modified from Clark and Fritz, 1997).

Webb and Longstaffe, 2010). Corn (the origin of the carbon in the CO_2 to be injected) is a C_4 plant with a $\delta^{13}C$ signature specifically ranging −16‰ to −12‰ (O'Leary, 1988). However, Figure 8 shows that atmospheric $\delta^{13}C$ signature can be as low as −10‰, which is also similar to the groundwater results from this study and ranges shown in Figure 8 (about −20‰ to nearly 0‰). Therefore, more investigation is needed, such as isotopic analysis of the RTE CO_2 stream, to validate this technique for the RTE CCS site.

Discussion

Near-surface sampling is a component of a larger long-term monitoring plan required for a North Dakota CO_2 SFP (Figure 9). Long-term CCS monitoring programs are developed to 1) show that groundwater and soil environments are not adversely impacted by geologic CO_2 injection,

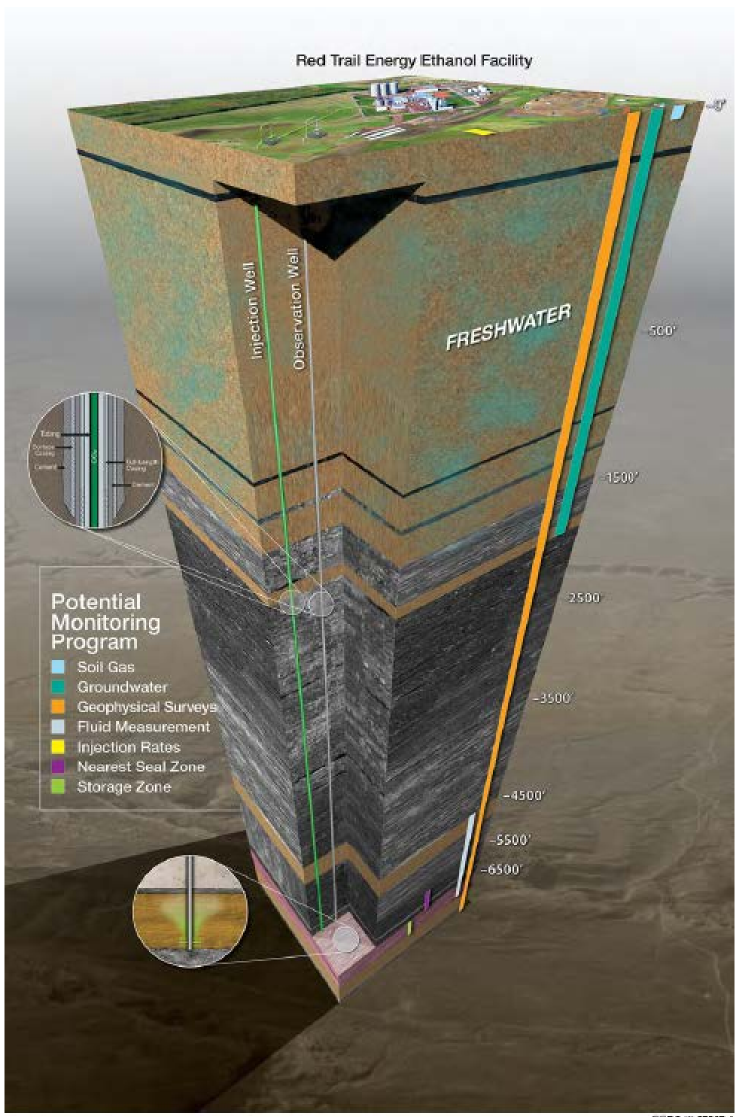

Figure 9. Examples of potential monitoring techniques that could be included in a monitoring plan, a North Dakota CO_2 SFP requirement.

2) determine effective markers that would trigger further investigation, and/or 3) provide timely mitigation when necessary. Therefore, baseline near-surface monitoring determines the naturally existing concentrations and seasonal variations in groundwater and soil gas chemistries to assist in developing a detailed, compliant monitoring plan. All techniques chosen, such as near-surface sampling, geophysical (seismic) surveys, and subsurface equipment in the storage and overlying zones, work in conjunction for a monitoring program that will be effective throughout the lifetime of a CCS effort.

A dedicated groundwater-monitoring well is required for a North Dakota CO_2 SFP to monitor the lowermost USDW, i.e., the Fox Hills Formation at the RTE CCS site (~1800-foot depth). All groundwater samples collected must be analyzed by a state-certified laboratory to report results for the permit application and all subsequent reporting once the permit is approved. NDIC has stated a preference for this monitoring well to be located on the pad of each CO_2 injection well, with a minimum of two sampling points. For the RTE CCS site, this translates to installation of a groundwater-monitoring well at the chosen injection site and continued sampling from the other Fox Hills residential well included in this study.

For continued soil gas sampling, the EERC recommends installing semipermanent soil gas profile stations (SGPSs), which provide more consistent and representative results. It has been observed through other studies (Leroux and others, 2018b) that the lower depths of the SGPSs (down to 14 feet) and the protected access points yield more effective and consistent data collection. During this sampling effort at the RTE CCS study region, site access was difficult because of variations in localized soil disturbances (e.g., from farming and utility workers) and wetter-than-average weather conditions. Locations for the SGPSs should be focused on higher land areas with road access, such that neither accumulates water during a precipitation event or series of events. Locations should also take into account the predicted movement of the injected CO_2 in the subsurface (discussed further in the Reservoir Characterization section).

To further explore tracer options for inclusion in the long-term monitoring plan for the RTE CCS effort, the CO_2 stream from the RTE facility (i.e., for ultimate CCS) should be analyzed for carbon isotopic composition (δC^{13}). If the results show a significant difference from the current groundwater- and soil gas-sampling results in the RTE CCS study region, then markers that would trigger further investigation could be defined. Another option for using this technique is to add an isotopic tracer (i.e., with a substantially higher or lower δC^{13} signature) to the CO_2 stream prior to injection. Both options allow for monitoring of significant changes in measured isotopic composition as an additional tool in the near-surface component of the monitoring program to be developed.

RESERVOIR CHARACTERIZATION

A 3D seismic survey was acquired in March 2019 over 7.8 mi^2 of the study area (Figure 10). The objectives of the survey were to aid site characterization, inform well placement, provide information to update the existing geologic model and reservoir simulations, and serve as a baseline survey for future monitoring. The information gained will considerably enhance the

Figure 10. Seismic survey covered nearly 8 mi^2 of private rural land within the RTE CCS case study site east of Richardton, North Dakota.

geologic characterization of the site and will be useful for the North Dakota CO_2 SFP application process required to implement the first CCS site in North Dakota. If a commercial CCS project is implemented, future seismic surveys can employ this initial survey as a baseline for monitoring and mapping the spatial extent of injected CO_2.

Seismic surveys are very useful for accurately assessing the viability of a target storage complex (Glazewski and others, 2018). Surface seismic surveys frequently constitute a major data element of site characterization by allowing visualization of geologic formations and the determination of physical property variations over large volumes of the subsurface. Seismic data provide information at lateral spatial intervals as short as tens of feet, which combined with nearby well data, yield highly informative subsurface geology snapshots encompassing large areas covering many square miles. Maps of surfaces at depth and vertical sections can identify and illustrate the approximate extent of significant geologic features including:

- Potential CO_2 migration pathways such as fractures and faults.
- Stratigraphic boundaries between formations.
- Formation dip that can direct CO_2 migration.

- Thickness of potential storage and sealing formations.
- Changes in rock type.
- Presence and geometry of structural features that may serve as CO_2 traps.
- Zones of differing porosity.

To extract this information, well logs from at least one well within the seismic survey area are needed to interpret the seismic response of the different geologic formations and match the depths of the geologic formations from the well data to the seismic data which are recorded in time. A stratigraphic test well within the 3D survey area began in March 2020. The modern well log data from this test well combined with the seismic data will increase the degree of confidence in the interpreted properties outlined above. Until then, a preliminary interpretation has been made by using the well logs from a nearby well to identify the geologic formations of interest. The seismic and well log data were used to interpret the boundaries between the different geologic formations and generate layers by tracing the boundaries. The infographic shown in Figure 11 provides a simplified overview of this process.

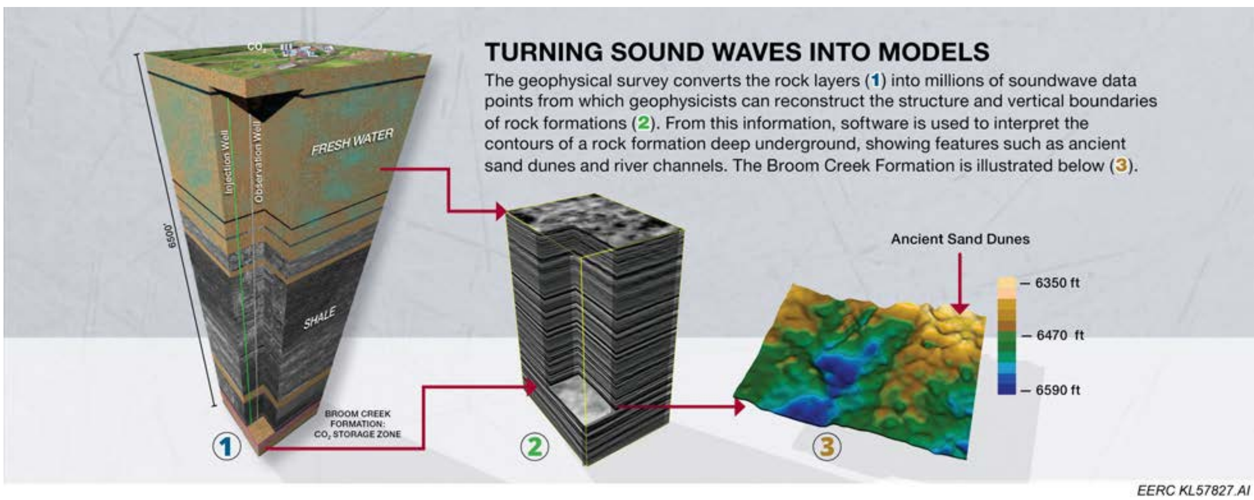

Figure 11. Infographic depicting the seismic data acquisition, processing, and interpretation process.

Geophysical Data Acquisition and Processing

Conducting a 3D seismic survey is a significant logistical challenge that requires planning and coordination with many stakeholders and occurs over several weeks. Tasks include seismic survey design, contractor selection, public and landowner engagement, and permitting. The first step for planning a 3D seismic survey is to generate an initial survey design. Considerations for the survey design should include the depth of the target formations, the area to be imaged by the seismic data, and surface constraints such as geographic and population features. Important variables such as the number of source locations, sensor locations, distribution of data points from the target formations, and range of source and sensor offsets should be computed to ensure the quality of the seismic data collected will meet the project objectives.

Once an initial survey design is generated, it is included in bid requests as part of contractor selection. The selected contractor is required to obtain a permit from the appropriate state agency, which in North Dakota is NDIC. North Dakota permitting requirements for a seismic survey are provided in North Dakota Century Code (NDCC) Section 38-08.1-04.1 (Exploration Permit) and NDCC Chapter 38-11.1 (Oil and Gas Production Damage Compensation). The permit application requires a bond payment, the seismic survey design, landowner notifications (that include copies of both codes), and a notarized affidavit testifying that notifications were received. At the conclusion of the survey, a completion report including maps of the final source and sensor locations is required.

The Public Outreach for North Dakota CCS section of this report provides information regarding landowner and community interactions related to the RTE seismic survey. The survey is a highly visible activity, with several field crews on all-terrain vehicles and seismic source vehicles such as large vibroseis trucks as well as visible sensors and data loggers (Figure 12). Public outreach such as supplemental fact sheets, presenting to city and county officials, and press releases are recommended in addition to the required landowner notifications.

Figure 12. Vibroseis trucks from the RTE seismic survey (top) and seismic data loggers, with the RTE facility in the background (bottom).

After field data acquisition is completed, the raw recorded data are transferred to a seismic data-processing contractor for compilation to an interpretable product. Once the data are processed, specialized software is used to match the seismic data to well data with known depth and geologic interpretations. After matching, the seismic data are used to evaluate subsurface features and provide input into geologic modeling and numeric simulations (e.g., forecast of injected CO_2 storage and movement in the target formation).

RTE Seismic Results

The top and bottom surfaces of the target injection formations provide insight about the structure of the storage zone, such as identifying structural features that may influence the movement of injected CO_2 as it diffuses into the storage zone. This initial interpretation of the seismic data used the well logs from the nearby Rummel-State #1 well (located to the southwest of the seismic survey area) to calibrate the seismic data, extract formation characteristics (i.e., depths, thickness, etc.) and inform placement of the stratigraphic test well.

Significant physical information was acquired about two potential injection zones for the RTE CCS effort: 1) the Broom Creek Formation and 2) the Inyan Kara Formation. Results estimated 3000 feet of confining zone between the Broom Creek Formation (storage target) and the lowermost USDW (Fox Hills Formation). Results also estimated the thickness of the Broom Creek injection target, which varies 230–420 feet within the survey area at a depth of about 6400 feet. The Inyan Kara Formation may be a viable alternate injection target as it contains several sand intervals approximately 410 feet thick at a depth of about 4800 feet. The results did not identify any issues that would prevent the project from moving forward.

The interpreted seismic surfaces were used to calibrate 3D geologic models for the RTE CCS case study (Figure 13). The improved geologic model allowed for updated forecast

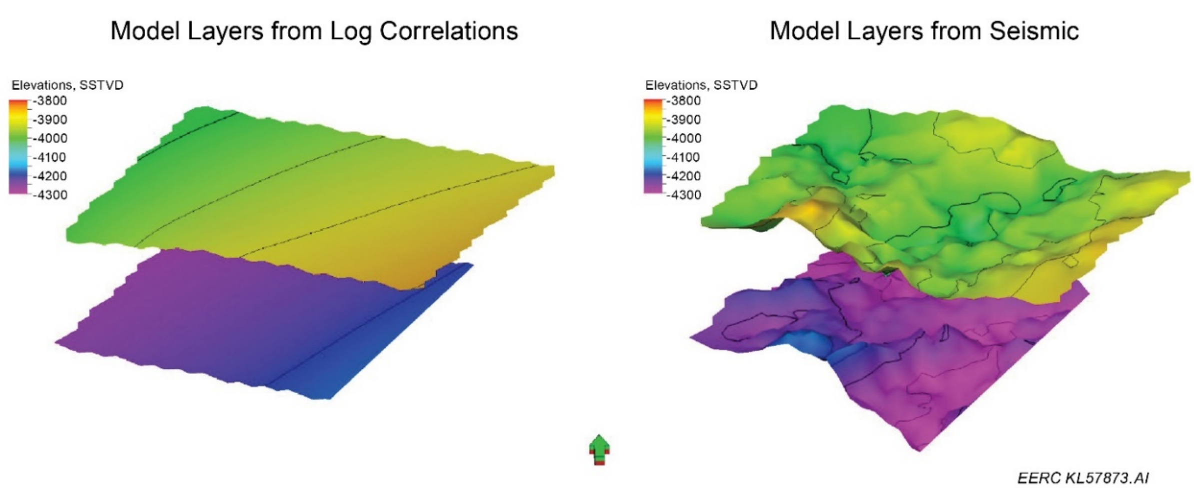

Figure 13. Interpreted surfaces for the top and bottom of the target Broom Creek injection formation. The dense spatial sampling of seismic data allows for much more detail (right) than straight-line well-to-well correlations (left) and were used to improve the accuracy of the geologic model and injection simulations.

simulations of the estimated movement of CO_2 in the target storage formations (Figure 14). The improved results informed the location of and characterization program for the stratigraphic test well (shown as RTE-10 in Figure 2). A stratigraphic test well is the recommended next step to acquire the remaining data necessary to validate the site for CCS and develop a North Dakota CO_2 SFP application.

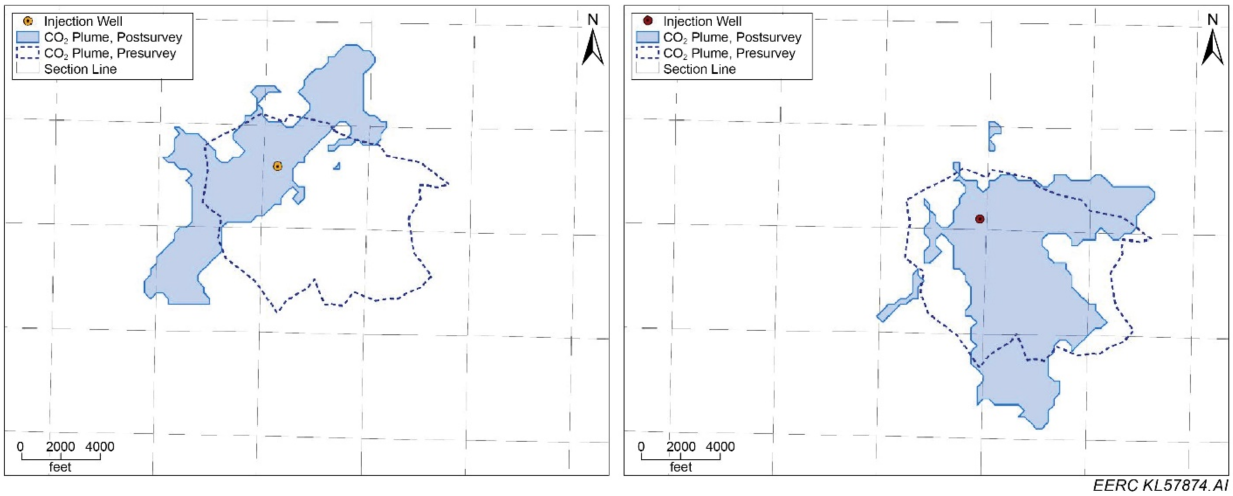

Figure 14. Simulated CO_2 plume shapes (blue) for two potential injection well locations computed after the geologic model was updated with the reservoir geometry as mapped from the seismic data. The dashed line indicates the plume shape computed before the seismic survey data were available.

NORTH DAKOTA DRILLING AND CO_2 STORAGE PERMITS

Drilling and CO_2 SFPs are required to construct and operate a geologic CO_2 storage project in North Dakota. RTE received approval to drill a stratigraphic test well (NDIC File Number 37229) on December 2, 2019. This stratigraphic test well is part of a critical path to achieving underground injection control (UIC) Class VI compliance and has laid the foundation for what is likely to be the first North Dakota CO_2 SFP application. Several recommended practices related to well design, geologic characterization, well testing, and the UIC Class VI requirements resulted from this permit process.

An NDIC application of permit to drill (APD) is required to drill a stratigraphic test well to acquire the necessary downhole data to complete a North Dakota CO_2 SFP. The NDIC Department of Mineral Resources (DMR) Oil and Gas Division has regulatory authority for geologic storage of CO_2 granted by NDCC (Chapter 38-22, Carbon Dioxide Underground Storage) and primacy to administer the North Dakota UIC Class VI Program (83 Federal Register 17758, 40 Code of Federal Regulations [CFR] 147; North Dakota Industrial Commission, 2013). The North Dakota Administrative Code (NDAC) (Chapter 43-05-01 Geologic Storage of Carbon Dioxide) contains the regulations that predominantly govern CO_2 storage activities in the state of North Dakota. DMR was engaged at the planning stages of permitting development to ensure compliance with potential CCS implementation.

A North Dakota Geologic CO_2 Storage Permits Template (Connors and others, 2020; Appendix C) was created for industrial CCS projects in North Dakota. The template covers 1) permit to drill a stratigraphic test well, compliant with UIC Class VI requirements and 2) CO_2 SFP applications. For example, Figure 15 provides illustrations regarding the various terms used to define permit requirements. This section, therefore, summarizes clarifications and lessons learned during this Phase III effort.

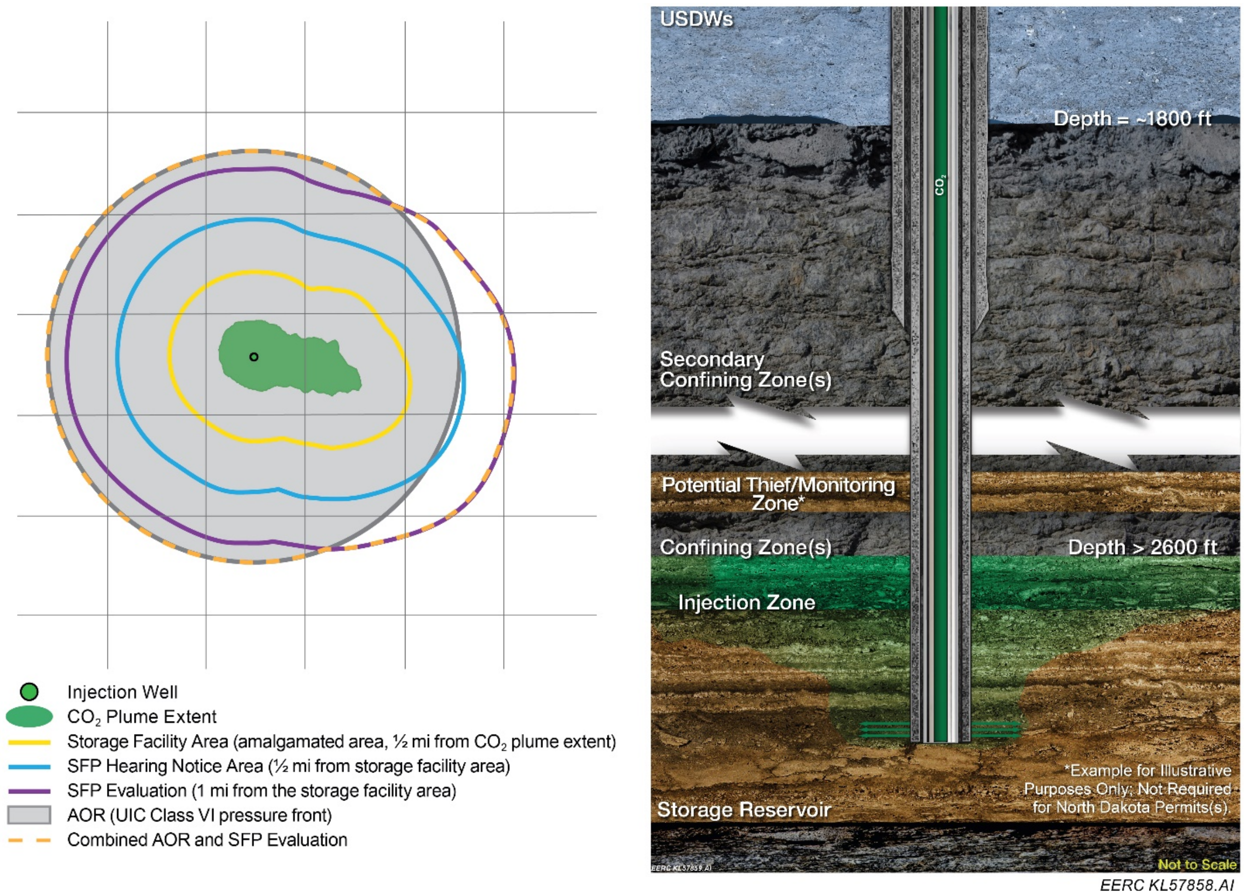

Figure 15. Surface (left; modified from NDIC DMR) and subsurface (right) terms regarding North Dakota APD and SFP requirements (Connors and others, 2020; Appendix C).

Permit to Drill

The North Dakota APD comprises prepermit filings and a permit application packet. The prepermit filings include 1) an organization report (NDIC Form 2), 2) an NDIC NorthSTAR account (for electronic filing), and 3) a single-well plugging and reclamation bond of $50,000. The APD packet (NDIC Form 1) includes several attachments such as the well location plat, well pad layout, geological prognosis, drilling prognosis, proposed mud and casing program, cement proposal, logging and coring program, surface agreement affidavits, and postcompletion plan. The

North Dakota DMR website (www.dmr.nd.gov/oilgas/rules/fillinforms.asp) contains links to the necessary forms as well as contact information for questions or issues.

The EERC and RTE explored development of a North Dakota APD with the intent of eventual geologic CO_2 storage permitting. Several discussions with North Dakota DMR occurred during developing stages to ensure accurate interpretation of NDAC sections, specifically regarding logging and coring requirements to comply with a North Dakota CO_2 SFP. For example, North Dakota DMR stated a preference for collection and analysis of geologic core through the CO_2 storage zone and a minimum of 50 feet from the overlying and underlying confining zones (Figure 16). These preferences and clarifications are included in the APD template (Appendix C).

NDIC-Stated Coring Preference: Include the collection and analysis of geologic core through the CO_2 storage injection zone and a minimum of 50 feet from the overlying and underlying confining zones. This is not a requirement but rather a recommendation from the NDIC. The purpose of this requirement is to demonstrate the depth and characteristics of the geology as it transitions between rock types from the target injection zone (i.e., impermeable lithology in the confining zones to a porous, permeable lithology in the injection zone). There can be porosity intervals above and below the Inyan Kara and Broom Creek Formations as the rock type transitions. Collection of sufficient core of the confining zones will aid the operator in demonstrating upper and lower confinement.

Figure 16. Example call-out box from the APD template (Appendix C).

North Dakota CO_2 SFP

The North Dakota UIC Class VI Program provides a process for potential project developers that wish to inject CO_2 for the purpose of geologic storage, including requirements to obtain a CO_2 SFP, a permit to drill, and a permit to operate prior to commencement of injection activities (North Dakota Industrial Commission, 2013).

The five primary components of the North Dakota CO_2 SFP are 1) pore space access, 2) geologic exhibits, 3) area of review exhibits, 4) supporting permit plans, and 5) injection well and storage operations. These topics form the basis for the NDIC public hearing to approve the SFP application. Required presentations by the CCS project team experts (e.g., project land man, project geologist, project engineer, etc.) may include pore space access details, geologic and area of review exhibits, and developed permit plans (e.g., operations, long-term monitoring, etc.). The permits to drill and inject/operate are separate applications that should be included in the completed CO_2 SFP application package upon submittal.

The EERC and RTE sought to clarify interpretations of the SFP regulations in collaborative discussions with North Dakota DMR. For example, installation of CO_2-compatible casing and cement is required only within portions of the wellbore anticipated to be exposed to CO_2 (e.g., injection zone, tubulars, packer, and wellhead; Fried, 2019). These clarifications (such as Figure 17) are included in the SFP template (Appendix C).

Casing and Cement: CO_2-resistant casing and cement are not required for the entire wellbore (e.g., surface casing and cement are not required to be CO_2-resistant). The well needs to be designed and constructed to withstand the effects of the CO_2. CO_2-resistant materials are required by NDIC for any portion of the well that will be in or near direct contact with the injected CO_2, such as the tubing and packer and the sections of casing and cement located in the injection zone and upper confining zone, etc.

Figure 17. Example call-out box from the SFP template (Appendix C).

Discussion

CCS efforts are subject to site-/region-specific geologic and operational factors; NDIC may require additional information for permit approval. Therefore, review of the relevant statutes and regulations in collaboration with NDIC representatives, city/county regulating authorities, and project partners is strongly recommended prior to submittal to ensure proper interpretation of North Dakota APD and CO_2 SFP application requirements and to ensure requirements are adequately addressed.

If also seeking to comply with CCS incentive programs, it is recommended to include program administrators in collaborations during CCS development stages to ensure project compatibility. These programs may have different (or potentially conflicting) requirements from permitting compliance. CCS incentive programs are discussed further in the following section.

ECONOMIC INCENTIVES EVALUATION

California, Oregon, the Internal Revenue Service (IRS), and other entities continued to mature incentive programs in 2019–2020, providing more substantive economic opportunities for CCS implementation at small-scale fuel production facilities. Additional states (Washington, Colorado) and countries (Canada, Brazil) have proposed legislation or feasibility studies to inform potential development of LCF programs for their regions.

Progress of Incorporating CCS into Established Programs

The California Air Resources Board (ARB) adopted several new rules under the Low Carbon Fuel Standard (LCFS) in January 2019, such as third-party verification, design-based pathways (DBPs), and the CCS Protocol (California Air Resources Board, 2018). Third-party validation by a California ARB-accredited entity is required for all new pathway applications, submitted on or after January 1, 2020, to obtain certified CI values applicable for credits through the LCFS carbon market. Information on the LCFS verification process and accredited parties is available on the California ARB website (ww2.arb.ca.gov/lcfs-verification). Several entities have garnered approval for validation of CCS reports (Table 3).

Table 3. California ARB Entities Accredited to Perform Verification Services for LCFS Data Reports Including CCS (ww2.arb.ca.gov/lcfs-verification)

Companies	Location
Ashworth Leininger Group	CA
EcoEngineers	CA
First Environment, Inc.	CA
Locus Technologies	CA
Rincon Consultants, Inc.	CA
SCS Engineers	CA
Tetra Tech, Inc.	CA
Trinity Consultants Inc.	CA
Christianson, PLLP	IA
NSF Certification, LLC	MI
Carbon Verification Service, LLC	MN
Adelante Consulting, Inc.	NM
Cameron-Cole	NY

The California LCFS DBP application provides a recently available option for a temporary (not certified) CI value for a fully engineered and designed facility prior to installation (i.e., no operational data). While the approved CI value cannot be used for credit generation, it provides confidence to investors and stakeholders that the fuel generated from the proposed facility could garner credits once certified. DBP applications must include a detailed life cycle analysis (LCA) of the anticipated pathway performed using the CA-GREET3.0 model, and an LCA report summarizing facility plans and specifications expected during commercial operation. A submitted DBP application is then posted by California ARB for public comment for 10–15 business days. The LCFS regulation states, “Only comments related to potential factual or methodological errors will require responses from the fuel pathway applicant.” RTE submitted a DBP application in September 2019 for potential ethanol–CCS and received approval from California ARB on February 28, 2020. As the first application to include a CCS component, the process was highly iterative, requiring numerous discussions with LCFS staff.

Oregon’s Clean Fuels Program (CFP) is drafting rules similar to the California LCFS Program, with proposed rule adoption later in 2020. Draft third-party verification rules were released for comment in September 2019. The Oregon CFP incorporated CCS verbiage for the first time in proposed draft rule changes, released December 2019 (Oregon Department of Environmental Quality, 2019). The Oregon Environmental Quality Commission must adopt proposed CFP rules for them to become active, and at the time of this report, a meeting to do so not been scheduled.

The CCS language in the draft Oregon CFP rules is general, lacking specificity and requiring significant clarification. For example, the end of the proposed verbiage states: “Reports must include measurements of relevant parameters sufficient to ensure that the quantification and documentation of CO_2 sequestered is replicable and verifiable. Oregon Department of

Environmental Quality (DEQ) may specify a protocol for measuring and reporting such information in its approval of such an application" (Oregon Department of Environmental Quality, 2019). At this time, it is unclear what Oregon DEQ considers to be a "relevant parameter" or what potential measurement/reporting protocols might be required. Although the Oregon CFP typically provides support and compatibility for certified pathways from the California LCFS, it is also unclear whether certification via the CCS Protocol will be accepted.

The IRS released a request for comments in May 2019 pertaining to guidance and clarifications for the Enhancement of Carbon Dioxide Sequestration Credit (a.k.a. Section 45Q) tax program. The deadline for submitting comments was July 2019. The IRS issued guidance in February 2020: 1) IRS Notice 2020-12 "Beginning of Construction for the Credit for Carbon Oxide Sequestration under Section 45Q" and 2) IRS Revenue Procedure 2020-12 "Examination of returns and claims for refund, credit or abatement; determination of correct tax liability." These documents provide broad guidance in lieu of taxpayers requesting private letter rulings in these areas. The guidance also addresses flexibility within the program such as project delays, structure of partnerships, and transferability of activities constituting start of construction (Figure 18). The CCS industry continues to wait for clarification on whether the IRS will accept alternative reporting criteria, such as the International Organization for Standardization 27914 for geologic CO_2 storage and the North Dakota UIC Class VI Program. The IRS anticipates issuing further guidance on issues such as secure geologic storage, utilization qualifications, and recapture of claimed credits; the additional guidance is expected to increase confidence for project developers by providing clarity around the tax credit program.

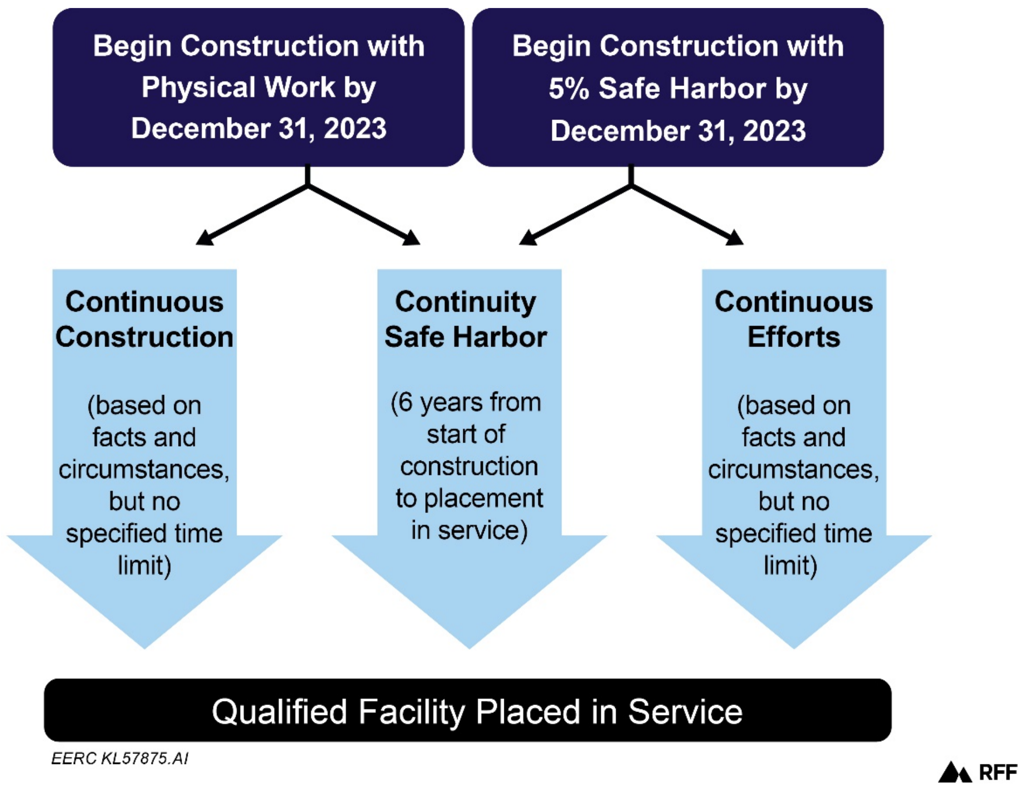

Figure 18. IRS Section 45Q eligibility from beginning construction through placement in service (Bartlett and Krupnick, 2020).

California LCFS Discussion

Establishing early and frequent communication with California LCFS staff, particularly the CCS Protocol team, is highly recommended during CCS development stages to determine compliance for permanence certification and with the UIC Class VI permitting process. For example, the CCS Protocol requires "a permanent, downhole seismic monitoring system" regarding microseismic monitoring (California Air Resources Board, 2018), which is not required for a North Dakota CO_2 SFP. Through discussion with the CCS Protocol team, RTE and the EERC identified that fiber optic cable with DAS (distributed acoustic sensing) capability along the length of the injection wellbore could satisfy the LCFS monitoring requirement in this example. These types of clarifications have important financial implications for project development. Continuing this example, fiber optic cables increase CCS capital costs ~$500,000 (order-of-magnitude estimate) for well design, installation, and DAS-interrogator, not including operating, interpretation, and reporting costs. Alternative technologies/approaches such as shorter borehole arrays (e.g., in the groundwater-monitoring well) have not yet been discussed.

Several discussions were facilitated with North Dakota and California officials to determine compliance of subsurface characterization plans and CO_2 injection well designs developed for the RTE site. The draft logging/testing and coring programs and injection well design were first found compliant with North Dakota UIC Class VI regulations (discussed in the North Dakota CO_2 SFP section). Then, the programs and designs were discussed with the CCS Protocol geologist, who deemed them compliant with the LCFS CCS Protocol as well (Petrie, 2019). The North Dakota Geologic CO_2 Storage Permits Template (Appendix C) details these findings.

Several components of the CCS Protocol require further guidance, such as explicit requirements and processes regarding the third-party review (by a LCFS-certified geologist and petroleum engineer) and risk assessment for acquiring permanence certification (California Air Resources Board, 2018). Communication with the California LCFS CCS Protocol team will continue as RTE CCS efforts progress to help ensure CCS engineering designs, data collection programs, and application documents are compliant with California ARB's requirements for an ethanol–CCS pathway certification.

Emerging Carbon Reduction Incentives

The Colorado Energy Office issued a request for proposals in September 2019 inviting bids from independent contractors to conduct a Colorado LCFS feasibility study (Voegel, 2019). The study is to 1) estimate current vehicle emissions statewide and a 2030 forecast and 2) determine CI model options. The study has since been awarded, with completion expected by June 30, 2020.

In Washington State, the Puget Sound Clean Air Agency created under the state's Clean Air Act, including King, Pierce, Snohomish, and Kitsap Counties, released a draft Clean Fuel Standard (CFS) rule in October 2019 (Puget Sound Clean Air Agency, 2019). Similar to the Oregon CFP, the proposed program states compatibility with California LCFS CI certification and does not yet include any CCS language. The public comment period ended in February 2020, a summary of which was to be reviewed by the Puget Sound agency in March 2020 to discuss next steps moving forward.

Both the existing British Columbia Renewable and Low Carbon Fuel Requirements Regulation and the proposed Canadian CFS include CCS very briefly (one to two phrases) as a potential technology option to achieve emission goals, albeit with no pathway details. The British Columbia program was adopted in 2008 and is often referred to as an LCFS Program. The Canadian CFS was modeled after the British Columbia LCFS, with a proposed regulatory approach released in June 2019. The Canadian CFS is currently planned for official adoption by 2022 for liquid fuels (Government of Canada, 2019).

Another countrywide carbon reduction incentive in development is the Brazil RenovaBio program (Noyes, 2018). This market-based trading program utilizes the familiar CI standard, yet with unique requirements such as data per farmer from whom feedstocks are received. The program launched in December 2019 with tradeable carbon credits known as CBios (Guerra and Boutin, 2019).

In conclusion, regardless of the number of incentive CCS opportunities and their stage of development, the work conducted under Subtask 1.3 demonstrates that compliance with CCS economic incentives is possible but complex, yet necessary to support the business case for CCS implementation at small-scale industrial fuel production facilities.

PUBLIC OUTREACH FOR NORTH DAKOTA CCS

The approaches and lessons learned from the public outreach efforts conducted for the RTE CCS case study are applicable to most small-scale commercial CCS projects. Frequent activities were conducted to generate positive engagement with stakeholders and communities regarding CCS integration with North Dakota ethanol fuel production. Events and materials included community open houses with posters and hands-on displays, city and county commission meetings with informational packets, and project activity-focused fact sheets for all events and landowners; public website access was provided. Specific stakeholder groups targeted for engagement included landowners, residents, educators, and media within the region as well as city, county, and state officials with authority over project and CCS activities.

A Public Outreach Package for CCS in North Dakota (Crocker and others, 2020; Appendix D) was developed, which compiles recommendations for coordinating events and the final materials, to serve as a guide for CCS efforts in rural North Dakota communities. This section summarizes the outreach activities conducted during the Phase III project and pertinent lessons learned.

Commission Meetings, Landowner Interaction, and Open Houses

Stark County Commission and Richardton City Commission monthly meetings were attended prior, during, and following major project activities to convey information about planned actions, status, and outcomes. Attendance at these meetings proved particularly beneficial to fulfill specific notification requirements for state geophysical (seismic) survey and drilling permits; North Dakota DMR was sent a copy of all materials. RTE presented at each of the meetings, with the EERC providing material packets (detailed in the next section), ensuring consistent messaging and a main contact for questions. Commission members frequently stated appreciation regarding the updates. A summary of topics covered and dates presented is provided in Table 4.

Table 4. Summary of Commission Meetings Attended in Relation to Project Activity

Main Topic	Meetings: Dates	Project Activity/Status Discussed
Introduction, Notification of Geophysical Survey Permit Application	• Stark County: February 5, 2019 • Richardton City: February 13, 2019	• RTE CCS project introduction, plans for geophysical survey. • Community open house scheduled for March 6, 2019.
Geophysical Survey Concluded, Environmental Sampling Starting Soon	• Stark County: April 2, 2019 • Richardton City: April 8, 2019	• Geophysical survey complete, cleanup in progress. • Moving forward with seasonal soil gas and water sampling to establish base line for future use.
Geophysical Survey Outcomes, Plan to Submit a Permit to Drill Application for a Stratigraphic Test Well	• Stark County: October 1, 2019 • Richardton City: November 12, 2019	• Project updated: 3D geophysical survey complete. • Looking at two promising locations for well. • Through permitting process, city council will be asked to accept RTE CCS project.
Environmental Sampling Concluded, Permit to Drill Approved	• Stark County: December 3, 2019 • Richardton City: December 18, 2019	• Final 2019 environmental sampling event concluded in November. • Permitting test hole will collect rock cores, formation fluids, and wireline logging data. • Community open house scheduled for December 11, 2019.

Individual landowners were personally contacted by RTE regarding notifications and access agreements for the geophysical survey, environmental sampling, and drilling activities. Personalized letters and maps were generated for each encounter, and information packets specific to the project activity were provided for each event. The one-on-one communication facilitated timely fulfillment of any notification and agreement requirements (Table 5).

Two community open houses were held in Richardton, North Dakota, in March 2019 and December 2019. The first event (Figure 19) had an open forum approach with poster displays that introduced the RTE CCS effort and described the geophysical (seismic) survey and equipment. A

Table 5. Summary of Landowner Communications in Relation to Project Activity

Letter Topic; Date	Landowners Contacted	Project Activity/Status Discussed
Geophysical Survey Notification and Access Discussion; February 2019	• 31 letters for landowners directly within survey area • 16 letters for landowners within ½ mile of survey boundary	Requested acknowledgment receipt of NDCC information and discussed geophysical survey details.
Geophysical Survey Conclusion; March 2019	• 22 letters for landowners directly within survey area • 21 letters for open house participants who signed guestbook	Thank you for granting land access for survey and attending open house.
Post Geophysical Survey Contact; August 2019	• 30 letters for landowners directly within survey area	Generalized survey results/outcomes.
Environmental Sampling Introduction; May 2019	• Six letters for chosen landowners with deep groundwater wells within RTE CCS study region • Five letters for chosen landowners meeting optimal soil gas sampling criteria within RTE CCS study region	Request permission to access land to 1) evaluate potential groundwater- or soil gas-sampling location and 2) collect water and/or soil gas samples seasonally (three times) in 2019.
Environmental Sampling Results; August 2019, November 2019, and April 2020	• Two to three letters for landowners with deep active water wells that granted access for groundwater sampling • Five letters for landowners that granted access for soil gas sampling	Groundwater and/or soil gas sampling results from May, August, and November events (respectively) specific to each individual landowner.

hands-on display explained how geologic CO_2 storage works. The second event (Figure 20) started with a presentation program to update participants on the RTE CCS effort including geophysical survey results and upcoming drilling activities. An open forum followed, with updated poster displays providing participants additional opportunities to learn about the project and ask questions. Both events were attended by RTE and EERC representatives and about 30 community visitors.

EERC KL56189.AI

Figure 19. EERC personnel discussing the project with Richardton community members at the open house held in March 2019.

EERC KL57876.AI

Figure 20. RTE (left) and EERC (right) personnel discussing the project with Richardton community members at the open house held in December 2019.

Project Materials and Dissemination

A cache of project activity and CCS-focused fact sheets, posters, and a project webpage (undeerc.org/RedTrailEnergy) was generated for the described events and media interviews to support public knowledge and acceptance of North Dakota CCS. Information was disseminated through traditional media, social media, and websites. Materials summarizing the near-surface monitoring (groundwater and soil gas sampling) and characterization (geophysical survey) activities were generated to inform and engage landowners and the community. Table 6 summarizes the materials generated for each type of event (see Appendix D for details and examples).

Table 6. Summary of Materials Generated for Project Meetings and Events

Product Type	Meeting/Event
RTE CCS Project Fact Sheet	Commission meetings, landowner contact, media contact, state regulator contact, community open house
Project Activity FAQs: Geophysical Survey, Environmental Sampling, Survey Results/Outcomes	Commission meetings, landowner contact, media contact, state regulator contact, community open house
Posters	Community open house
Press Releases	Commission meetings, open house, media inquiries
Public Notice in Local and Area Newspapers	Geophysical survey
Invitations	Community open house
Talking Points	Commission meetings, survey notification, land access request, survey results distribution, sampling results distribution, media inquiries

Outreach Lessons Learned and Recommendations

All in-person outreach efforts included presentations on project activities with the opportunity to ask questions and written materials including contact information. To date, feedback has been generally positive, and interactions have generally been constructive. In the information age, early, proactive public outreach with stakeholders is critical to the success of new technology and infrastructure development. Every encounter with the public—positive and negative—makes an impression that can have impacts beyond the current activity and the local project. The RTE CCS case study outreach recognized the importance of developing and maintaining credibility for CCS as it paved the road for future CCS projects around the state.

Adaptability was a key lesson learned for effective outreach during Phase III activities. For example, media would often make contacts outside of the RTE CCS effort, such as contacting North Dakota DMR when permitting occurs. Media packets are now generated for each public meeting and are on hand at RTE, and North Dakota DMR is given copies of all materials to stay informed of project status and information released. In addition, scheduling open house events to follow landowner interactions led to greater participation and curiosity regarding project activities and the overall RTE CCS effort.

Consistent messaging is needed to help audiences understand how CCS technology can be implemented safely. Encounters can occur anywhere, anytime, ranging from planned events (e.g., an open house) to casual conversation (e.g., local café, gas station, etc.). Given the rural close-knit communities near the RTE CCS study region, encounters will be shared among community members. Providing opportunities for community members to be heard not only generates positive attitudes toward the project team, but also reveals important concerns to be discussed as this region's first-of-its-kind facility moves forward.

CONCLUSIONS

The RTE CCS case study is demonstrating how small-scale commercial CO_2 emitters might economically implement and operate CCS infrastructure and engage in the CCS industry. Several guidance documents were generated to assist with this effort, including a CO_2 Capture PDP (Piggott and Vance, 2019; Appendix A), North Dakota Geologic CO_2 Storage Permits Template (Connors and others, 2020; Appendix C), and Public Outreach Package for CCS in North Dakota (Crocker and others, 2020; Appendix D).

Several engineering designs were solicited and assessed from vendors for the potential CO_2 liquefaction facility at RTE. The designs, specific to current RTE ethanol operations, were to process the average 180,000 tonnes of CO_2 generated annually for subsurface injection and geologic storage. The bids averaged a total cost of about $20 million, including equipment delivery and installation as well as storage tanks.

Baseline monitoring of near-surface groundwater and soil gas environments in the RTE CCS study region were conducted in May, August, and November 2019 to comply with North Dakota CO_2 SFP requirements. Monitoring for key indicators specific to groundwater and soil gas chemistries provides an effective means of complying with permit requirements for long-term monitoring. The data generated will also inform future installation of a permit-required groundwater-monitoring well and recommended SGPSs. Isotopes may also serve as key indicators for near-surface monitoring, requiring further investigation to be included in the RTE monitoring plan.

A geophysical (seismic) survey was acquired in March 2019 to verify the presence and structure of thick sandstone layers that may serve as a CO_2 storage reservoir and several thousand feet of overlying confining zones. Survey results also informed the location and characterization program for a subsequent stratigraphic test well. The stratigraphic test well will provide site-specific geologic data to validate these survey results and acquire remaining data necessary to develop a North Dakota CO_2 SFP application.

RTE obtained a permit to drill, approved by NDIC on December 2, 2019, for a stratigraphic test well that is designed to provide a transition pathway to UIC Class VI compliance. Several recommended practices and clarifications resulted from the permit process, including 1) collection and analysis of geologic core through the CO_2 storage zone and a minimum of 50 feet in the overlying and underlying confining zones and 2) installation of CO_2-compatible casing and cement, only required within portions of the wellbore anticipated to be exposed to CO_2 (e.g., injection zone, tubulars, packer, and wellhead). A template was created to assist industrial CCS projects as they progress toward development in North Dakota. The template includes 1) an APD for a stratigraphic test well, compliant with UIC Class VI data requirements, and b) a CO_2 SFP application.

Although other entities continued to mature incentive programs in 2019–2020, California and the IRS currently provide the most advanced economic opportunities for CCS integrated with fuel production. The development of RTE's APD provided the opportunity to garner compliance agreement from California LCFS CCS Protocol officials for NDIC-approved downhole testing/logging and coring programs and conceptual CO_2 injection well designs. RTE also received approval of an LCFS DBP for potential ethanol–CCS from the California ARB on February 28, 2020, providing confidence to progress the project and supporting investment for a fully designed facility. The IRS issued guidance in February 2020 that addresses the definition of the beginning of construction and revenue procedure on partnerships for the Section 45Q tax credit program; the IRS anticipates issuing further guidance on issues such as secure geologic storage, utilization qualifications, and recapture of claimed credits.

Outreach was an integral part of several project activities conducted during Phase III, specifically the geophysical survey, environmental sampling, and acquiring an approved permit to drill. Overall, project outreach events and materials generated positive engagement with stakeholders and communities regarding CCS integration with North Dakota ethanol fuel production. Face-to-face interaction proved most effective with landowners, community residents, city/county commission members, board members, and regulatory officials. Concerns to date have centered on human safety, groundwater and environmental protection, clarity and full disclosure regarding the project moving forward, and the trustworthiness of the project team and regulators.

The results of Phase III have allowed project partners to move closer to implementing the first integrated ethanol–CCS effort in North Dakota, capitalizing on evolving economic incentives. The positive outcomes of the technical and economic potential point toward continued progress for North Dakota ethanol–CCS implementation.

FINAL STEPS TO CCS IMPLEMENTATION

The RTE CCS case study provides a road map toward successful integration of commercial-scale CCS with small-scale industrial fuel production. The following list provides a summary of the major components for execution of CCS installation and operation at the RTE CCS site:

- Outreach
  - Continue public outreach surrounding highly visible activities (e.g., drilling, construction, sampling, permitting) in advance to provide notice and opportunities to answer any questions/concerns

- Provide relatable materials/actions (e.g., fact sheets, press releases, open houses, website updates, direct landowner communication)
- Drill stratigraphic test well
  - Contract drilling, core and testing vendors and engineers
  - Drilling with geologic core collection, downhole testing and logging, fluid sampling
  - Install downhole monitoring (e.g., pressure/temperature [P/T] gauges, fiber cable, etc.); and well casing, cement, and wellhead
- Characterization
  - Laboratory analyses of collected core and fluid samples
  - Technical evaluation of laboratory and downhole testing/logging results
  - Finalize maps, diagrams, modeling/simulations, etc., required for permitting
- Monitoring
  - Install SGPSs, groundwater well for long-term near-surface sampling
  - Establish downhole data management and evaluation protocols (e.g., P/T gauges, fiber cable, etc.)
  - Finalize long-term monitoring plans required for permitting
- North Dakota permitting
  - Finalize documents and submit applications: CO_2 SFP, permit to drill, and permit to inject/operate
  - Prepare for NDIC public hearing
- Incentive Programs
  - Communicate with authorities to ensure designs and plans are compliant with both permitting and program requirements
  - Determine and provide any required documentation/applications for official certification, qualification, etc.
- CO_2 capture system and pipeline
  - Contract vendors and engineers, order equipment
  - Site construction and system installation
  - Shakedown testing and operations optimization
- Drill injection/monitoring well(s)
  - Contract drilling vendors and engineers
  - Drilling, well installations/perforations
- CCS system operation
  - Integrate all systems and shakedown testing
  - Optimize ethanol–CCS operations
  - Initiate required monitoring and reporting plans

RTE is moving further toward CCS implementation, drilling a stratigraphic test hole in March 2020. This activity will provide the necessary downhole data at the site to 1) develop a North Dakota CO_2 SFP application, 2) finalize the CO_2 liquefaction facility design, and 3) develop a certification application under the LCFS CCS Protocol. If achieved, the site will generate the first integrated CCS facility in North Dakota.

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APPENDIX A

CO_2 CAPTURE PROCESS DESIGN PACKAGE

RED TRAIL ENERGY CO_2 CAPTURE FACILITY PHASE III COST ESTIMATE AND PROCESS DESIGN PACKAGE

ENERGY AND ENVIRONMENTAL RESEARCH CENTER

This document has been revised as indicated below and described in the revision record on the following page. Please destroy all previous revisions.

Rev N°	Date	Originator's Name & Initials	Reviewed/Checked By Name & Initials	Description	Pages
0	09/30/19	BDP/AEV	RWM	Final Report	ALL
1	11/20/19	BDP		Revised for Content	ALL

Table of Contents

1 Summary and Conclusions

In this phase of the CO_2 capture and sequestration project at the Red Trail Energy (RTE) ethanol facility in Richardton, North Dakota, Trimeric developed a process design package (PDP) for a CO_2 liquefaction facility. The facility captures carbon dioxide produced in RTE's fermentation process, compresses the CO_2 up to approximately 350 psig, dehydrates the gas, and then liquefies it using a closed-loop ammonia refrigeration process. A conventional distillation column distills the liquid CO_2 to remove oxygen, in addition to other non-condensable gases. Liquid product CO_2 from the distillation column flows to storage tanks, where it can be sold to third parties via truck or injected into a local formation for geologic storage.

This PDP includes process flow diagrams in Appendix A, basic P&IDs in Appendix B, and a preliminary plot plan in Appendix C. The facility designed in this project is capable of processing 587 tonnes per day of CO_2, and recovers nearly all of the CO_2 emitted by RTE in their fermentation process. A small vent stream from the distillation column will be the only emission from the facility in this design. Trimeric also developed a request for quotation and solicited bids from three different equipment manufacturing firms that design and build liquid CO_2 facilities. During the bid process, RTE requested the facility be able to process 115% of the maximum design basis case, or 675 tonnes per day of CO_2. Details of the bid results are available in a separate document, but the average purchased equipment cost for the liquefaction facility equipment from the bidding process was $10,700,000. Table 1 shows the expected total installed cost for the CO_2 liquefaction facility at RTE using the average purchased equipment cost from the bidding process.

Table 1. Estimated Capital Cost for Liquefaction Facility with Manufacturer Bids.

Purchased Equipment Cost (Excluding Storage Tanks)	$10,700,000
Expected Installation Costs (Excluding Storage Tanks)	$6,300,000
Storage Tank Total Installed Cost	$2,600,000
Freight Costs (Excluding Storage Tanks)	$170,000
Total Installed Cost Estimate	$19,770,000

Utilities required for the liquefaction facility include electricity, cooling water, waste water disposal, water make up, and instrument air. Electricity is by far the largest utility need for the facility; the CO_2 liquefaction process involves compression of the feed gas and compression of the refrigerant system. Trimeric estimates the electrical requirement for liquefying and injecting the CO_2 at RTE to be 153.6 kWh/Tonne. Table 2 shows a summary of the estimated utilities required for this process.

Table 2. Major Utilities for Liquefaction Facility.

Utility	Expected Consumption
Electricity	3,763 kW
Cooling Water Circulation	3,610 gpm
Waste Water	9 gpm
Make Up Water	57 gpm
125 psig Steam	1,156 lb/hr
Instrument Air	1,760 SCFH

Some opportunities to optimize the capital and operating cost of the facility should be investigated further if the project moves forwards past this phase. This includes:

- Evaluate the need for liquid CO_2 storage tanks. The RTE liquefaction facility will initially inject most or all of the CO_2 captured from the fermentation area, and not sell any CO_2 to third parties. In this design, there is no need to have bulk storage of liquid CO_2 on-site, and the potential cost savings of $2,600,000 by removing the storage tanks from the scope of the project is significant. Provisions can be made to include storage tanks in the future if the CO_2 can be sold to third parties or additional CO_2 received from third parties for injection is realized.
- Evaluate using liquid ammonia for the heating medium in the E-503 CO_2 Product Heater. This heater currently uses utility steam to heat the high pressure liquid CO_2, but liquid ammonia from the V-608 NH_3 Receiver could be used instead. This would subcool the liquid ammonia, which makes the refrigeration system more efficient while still heating the liquid CO_2 adequately. One potential drawback to this optimization is that injection would need to stop if the liquefaction facility was offline for some reason, and if CO_2 imports come to the facility for injection, they would need to stop as well. However, if storage tanks are eliminated from the project, there will be no CO_2 to inject if the liquefaction facility is offline.
- Evaluate the design of the E-607 NH_3 Condenser. The higher the condensation temperature of the ammonia, the more horsepower will be required for the C-601 NH_3 Compressor. As a result, the lowest operating cost for the facility will be achieved by condensing the ammonia refrigerant at a temperature as close to the wet bulb temperature as practical. One manufacturer proposed a wet surface air cooler for the E-607 NH_3 Condenser, which is a hybrid cooling tower design where a thin film of water is sprayed over the exchanger tubes while air is forced over the condenser tube banks. This design

minimizes the condensation temperature of the ammonia, but costs an additional $400,000 of upfront capital investment.

2 Background

The Red Trail Energy (RTE) ethanol facility in Richardton, North Dakota produces ethanol by fermenting corn. During the fermentation process, carbon dioxide (CO_2) produced by the yeast bubbles out of the fermenting liquids, is scrubbed with water to remove alcohols and other volatile organic compounds, and then vents to atmosphere. RTE, the Energy and Environmental Research Center (EERC), and Trimeric Corporation (Trimeric) worked to design a CO_2 capture facility that will inject the captured CO_2 in a local formation so that RTE's ethanol can qualify for low carbon fuel standards and federal tax credits.

This phase of the project provided RTE with a process design for a facility that captures the CO_2 from the scrubber before it vents to atmosphere, and then compresses, liquefies, and purifies the CO_2. In previous phases of the project, Trimeric provided the EERC and RTE with preliminary process designs of different CO_2 capture facilities, and helped facilitate source gas CO_2 characterization. This report details the process design of the liquefaction facility, and provides RTE and the EERC with utility estimates for the liquefaction facility. Separate from this report, detailed +/- 10% accuracy proposals were provided by equipment manufacturers with CO_2 liquefaction expertise so that the project team could more accurately develop the investment case for the capture facility.

3 Design Basis and Feed Gas Composition

The CO_2 vented by RTE is very pure CO_2, typically more than 99% molar CO_2 on a dry basis. Trimeric identified three different facility designs in the initial phase of the project that would produce different levels of CO_2, including:

- Food and beverage quality CO_2 facility. This facility would produce a high purity liquid CO_2 product, suitable for use in the food and beverage grade industry. CO_2 would be loaded onto trucks for sale to third parties. This CO_2 has a high commercial value, but very tight specifications, and requires the most capital investment and the most cost per ton of CO_2 produced. RTE did not select this facility for this phase of design.
- Injection quality CO_2 facility. This facility produces a high pressure liquid CO_2 product for injection into a formation. The only impurity removed from the CO_2 is water, and the CO_2 has the lowest commercial value. Oxygen is not removed from the CO_2, which makes it unsuitable for use in enhanced oil recovery operations. This facility has the

lowest capital investment required, and the lowest cost per ton of CO_2 produced. RTE did not select this facility for this phase of design.

- EOR quality CO_2 facility. This facility produces a high pressure liquid CO_2 product for injection into the formation, or a medium pressure liquid CO_2 product for sale to companies that need CO_2 for industrial or enhanced oil recovery operations (but not food and beverage grade operations). This facility has a capital cost investment between the two other facility designs, and an almost identical cost per ton of CO_2 produced to the food and beverage grade facility. RTE selected this facility for this phase of the project.

More details on the food and beverage grade CO_2 facility and the injection quality CO_2 facility can be found in Trimeric's earlier report, *Red Trail Energy CO_2 Capture and Sequestration Project CO_2 Surface Facility Design Report* issued on May 8, 2017.

RTE hired a third party to characterize the gas vented by the CO_2 Scrubber. Accurate analysis of the feed gas to the capture facility is critical, particularly when the facility will produce a liquid product. The presence of gases that do not condense at the CO_2 liquefaction temperature and pressure will determine how much of the CO_2 is recoverable as a liquid. Table 3 shows a summary of the feed gas composition measured by the third party; a detailed analysis of the feed gas can be found in a separate document provided by the analysis company.

Table 3. CO_2 Feed Gas Composition.

Gas Species	**Fraction (Mole % or ppmv as indicated, dry basis)**
Carbon Dioxide (CO_2)	99.9+%
Oxygen (O_2), Nitrogen (N_2), Total Hydrocarbons, Total Sulfur	< 1,000 ppmv
Water (H_2O)	Saturated at feed gas conditions

RTE confirmed that this analysis met their expectations for the CO_2 source gas. Discussion with RTE operating personnel indicates that they make efforts to minimize the potential for air ingress into the fermentation system so the low amounts of oxygen and nitrogen are to be expected. The required product purity from the liquefaction facility is shown in Table 4.

Table 4. CO_2 Product Specification.

Species	Limit
Carbon Dioxide (CO_2)	> 95 mol. %
Oxygen (O_2)	< 10 ppmw
Water (H_2O)	< 30 lb/MMSCF (633 ppmv)
Hydrogen Sulfide (H_2S)	< 20 ppmw
Total Sulfur	< 35 ppmw
Nitrogen (N_2)	< 4 mol. %
Hydrocarbons	< 5 mol. %

The feed gas already meets most of the required product specifications, with the exception of water and oxygen. The proposed liquefaction facility removes the water and oxygen from the CO_2 to meet the specifications shown in Table 4.

The liquefaction facility will be sized to process all of the source gas. Required CO_2 product conditions are provided in Table 5.

Table 5. CO_2 Delivery Requirements During Normal Operation.

Delivery Parameter	Project Design Requirement
Maximum Flow Rate	Maximum total flow at plant inlet 600 MTD (11 MMSCFD)
Minimum Flow Rate	Minimum total flow rate at plant inlet 300 MTD (6 MMSCFD)
Normal Pressure at Injection Wellhead	1,500 psig (maximum) at normal delivery temperature based upon the latest estimate from EERC.
Maximum Temperature at Inlet to Pipeline	120 °F
Minimum Temperature at Injection Wellhead	60 °F

The following sections detail the design basis for the potential CO_2 liquefaction facility for the Red Trail Energy site. Note that specific mass balances and utility values are considered business-sensitive.

4 Plant Layout and Process Description

Trimeric developed process flow diagrams (PFDs), heat and material balances (HMBs), basic piping and instrumentation diagrams (P&IDs), and a basic plot plan for the liquefaction facility as a part of this project. PFDs can be found in Appendix A, the P&IDs can be found in

Appendix B, and the basic plot plan can be found in Appendix C. The rest of this section is a description of the process flow and key operating conditions for the liquefaction facility. The PFDs may be used as a reference in this section.

4.1 Inlet Blower Area

The CO_2 feed stream exits the ethanol facility's CO_2 Scrubber near atmospheric pressure; the discharge of the CO_2 Scrubber is the battery limit for the inlet blower area. The gas stream enters the V-100 Blower Inlet Separator to remove any liquids that might have condensed or carried over from the ethanol facility CO_2 Scrubber. Liquids collect in the bottom of the separator and are pumped to the ethanol facility for disposal. The gas flows from the top of the separator to the B-102 CO_2 Inlet Blower, which compresses the gas from near atmospheric pressure up to 15 psig. Hot compressed gas from the blower flows to the E-103 CO_2 Blower Aftercooler to reduce the temperature of the gas stream and condense some water out of the gas stream. The cooled gas/liquid mixture flows to the V-104 CO_2 Blower Aftercooler Separator where liquids are removed from the gas stream and sent to the ethanol facility for disposal. The gas flows through a 16" line that will be about 400 feet long to carry the gas from the fermentation area to the liquefaction area. RTE did not want the open space around the fermentation area used up in case the ethanol facility expands in the future and requires more fermenters.

4.2 Liquefaction Area

In the liquefaction area, the gas first passes through the V-200 CO_2 Compressor Inlet Separator to remove any water that may have condensed in the line as the gas traveled through it. Liquid from the separator flows to the ethanol facility for disposal. The gas from the separator flows to an oil-flooded screw compressor, the C-201 CO_2 Compressor, which compresses the gas stream from approximately 14 psig up to 350 psig. The oil-flooded screw compressor technology injects oil into the process gas stream, and then compresses the oil and the gas up to the required discharge pressure. The gas and oil mixture flows out the compressor and into the V-206 CO_2 Compressor Oil Coalescer, which removes most of the oil from the gas stream. Oil collects in the bottom of the separator and flows through a cooling and filtering system (not depicted on the PFDs) so it can be reinjected into the compressor. Any compressor oil remaining in the gas stream can foul the downstream molecular sieve dehydration adsorbent, and essentially complete removal of the oil from the gas stream is required, so the V-207 CO_2 Carbon Bed downstream of the oil coalescer adsorbs any remaining oil from the gas stream.

Oil-free gas flows into a water-cooled aftercooler, the E-300 CO_2 Compressor Aftercooler, to reduce the gas temperature and condense water out of the gas stream. The cooled gas/water mixture flows into the V-301 Aftercooler Separator where liquid water is removed and sent to the ethanol facility for disposal. Gas from the separator flows to a refrigerant cooled exchanger, the E-302 Refrigerant Aftercooler, which cools the gas stream down to approximately 50 °F to condense as much water out of the gas stream as possible before flowing to the molecular sieve dehydration unit. The coolant for this exchanger is liquid ammonia, which vaporizes at an intermediate pressure in this exchanger. More details on the ammonia refrigerant system can be found in Section 4.4. The cooled gas/liquid mixture flows into the V-303 Refrigerant Aftercooler Separator where liquid water is removed and sent to the ethanol facility for disposal. Gas from the separator flows through the E-304 CO_2 Superheater, which raises the temperature of the gas stream to 60 °F to eliminate the need for stainless steel construction.

Up to this point in the process, the gas stream is saturated with water and the equipment must be able to resist corrosion from acidic water that may be present. As a result, separators, heat exchanger tube bundles, and piping are constructed out of 304 stainless steel. Downstream of the superheater (E-304), the facility may be constructed of carbon steel or low temperature carbon steel if necessary. Gas flows from the superheater into a molecular sieve dryer system, which adsorbs essentially all of the water vapor remaining in the gas stream in a pair of batch-operated vessels, the V-305A/B CO_2 Dryer Vessels. One of the vessels is always adsorbing water from the gas stream, while the other is offline being regenerated with dry product gas. A slip-stream of dry product gas (the recycle gas required to regenerate the spent bed is around 5% of the total gas stream flowrate) passes through a control valve down to approximately the CO_2 compressor (C-201) suction pressure and flows through the E-306 Dryer Regenerator Heater, which heats the regeneration gas up to 500 °F. Hot gas flows through the offline dryer vessel and desorbs the water from the adsorbent. The hot gas flows out of the dryer vessel, and is cooled in the E-308 Regeneration Cooler. As water desorbs from the offline vessel, some water will condense out of the gas stream in the regeneration cooler, and it is separated from the gas stream in the V-309 Regeneration Separator. Liquid collects in the bottom of the separator and flows to the ethanol facility for disposal. The regeneration gas flows out of the regeneration separator back to the suction of the CO_2 Compressor to minimize CO_2 losses in the system.

Dry gas flows out of the bottom of the online dryer vessel and into the E-400 CO_2 Main Reboiler. The dry gas exchanges heat with liquid CO_2 in the main reboiler and cools down to near the liquefaction temperature. The cold, dry gas flows out of the reboiler to the E-402 CO_2 Main Condenser, where it is liquefied by exchanging heat with evaporating refrigerant (see Section 4.4 for more details on the refrigerant system). Liquid flows out of the main condenser into the column feed drum (not depicted on the PFDs), and then is pumped by the P-404 CO_2 Column Feed Pump into the T-405 CO_2 Distillation Column. In the distillation column, noncondensable gases such as oxygen, nitrogen, and methane are stripped out of the liquid stream and flow out of the top of the column. Essentially pure CO_2 collects in the bottom of the distillation column and flows to the CO_2 Main Reboiler and E-401 CO_2 Auxiliary Reboiler. The Auxiliary Reboiler, which is part of the refrigeration loop, provides additional heat to the bottom of the column. A portion of the liquid CO_2 vaporizes and returns to the distillation column while the rest of the liquid CO_2 flows through the E-407 CO_2 Subcooler (E-407), where it exchanges heat with vaporizing refrigerant and subcools. Vapor from the top of the distillation column flows through the E-406 CO_2 Column Condenser, and exchanges heat with vaporizing refrigerant to condense some of the gas back to the liquid phase. The condensed liquids flow back to the column feed drum, and the remaining vapor vents to atmosphere. This maximizes the amount of CO_2 recovered by the process.

4.3 Storage and Injection Area

Pure CO_2 from the liquefaction area flows into the TK-500A/B/C CO_2 Product Storage Tanks, which operate at appx. 312 psig and -5 °F. From the storage tanks, the CO_2 may be pumped into trucks for sale to a third party, or it can be pumped to an injection well for geologic sequestration. The P-501 CO_2 Booster Pump pumps the liquid CO_2 up by 20 psi to provide adequate head for the P-502 CO_2 Injection Pump, which pumps the liquid CO_2 up to a pressure of 1,515 psig. The high pressure CO_2 flows through the E-503 CO_2 Injection Heater, and then through a local pipeline to the injection well for sequestration in a local formation. For this project, the injection well is 2,640 feet from the storage area.

4.4 Ammonia Refrigeration System

The ammonia refrigeration system is a closed-loop circulation system that provides refrigerant to the process. The refrigerant chosen for this project is anhydrous ammonia, which is a common refrigerant for liquid CO_2 facilities in other industries. Refrigerant is required in every exchanger that cools the process gas below the cooling water temperature. The heart of the refrigerant system is the C-601 NH_3 Compressor, which compresses ammonia vapor from atmospheric pressure up to a pressure at which the ammonia can be condensed in a water-cooled heat exchanger, the E-607 NH_3 Condenser. For the ambient conditions at RTE (and therefore the cooling water conditions), Trimeric estimated a condensing temperature of 92 °F which equates to a compressor discharge pressure of 189 psia. The condensed ammonia flows out of the NH_3 Condenser and into the E-608 NH_3 Receiver, which acts as a surge tank for the refrigerant system to absorb changes in demand as the flow rate of feed gas to the process changes, or the ambient conditions change substantially. Liquid ammonia flows out of the NH_3 Receiver and through two exchangers; the E-304 CO_2 Superheater and the E-401 Auxiliary Reboiler. Each of these exchangers subcools the liquid ammonia and makes the refrigeration loop more efficient.

Liquid ammonia then flows to other exchangers where it is vaporized to provide cooling to different parts of the process. The E-302 Refrigerant Aftercooler vaporizes medium pressure ammonia to cool the feed gas off to 50 °F while the E-402 CO_2 Main Condenser, the E-407 CO_2 Subcooler, and the E-406 CO_2 Column Condenser vaporize low pressure ammonia to cool or liquefy the CO_2. The vaporized ammonia flows out of each exchanger back to the C-601 NH_3 Compressor.

5 Process Simulation and Compressor Modeling Results – Utility Estimates

VMGSim v10.0 (Build 128) with thermodynamic model APR for Natural Gas 2 was used to model the CO_2 liquefaction and distillation process from the blower feed to injection. The same version of VMGSim with thermodynamic model Advanced Peng-Robinson was used to model the ammonia refrigeration loop. Process simulation models do not accurately characterize the power requirements or discharge conditions of screw compressors. This is due to the fact that the compressors are compressing a two phase mixture, and the liquid oil can absorb a substantial amount of the heat generated by compressing the gas. This allows for lower than expected discharge temperatures from the compressor, but larger horsepower requirements than expected and it is critical to remember that the circulating compressor oil must also be cooled in an exchanger before flowing back to the compressor. The ammonia screw compressor was modeled using the MYCOM MYselect software. The CO_2 screw compressor was modeled by MYCOM technical support.

5.1 Refrigerant Options

Several different options were investigated to determine the best design for this application. When picking a refrigerant, the energy requirement and the boiling point of the refrigerant are important factors. The lowest temperature in the process is at the condenser, which operates at -20 °F. Assuming a temperature approach of at least 10 °F for the heat exchanger, the refrigerant must have a boiling point of less than -30 °F at the suction pressure of the compressor. Four refrigerants were investigated for this process, as they have been used in the past for liquid CO_2 production. The refrigerants chosen for further investigation were:

- Anhydrous ammonia. This is the most common refrigerant for this process, and is used in many facilities across the United States. Anhydrous ammonia is toxic, and presents a health hazard to personnel if there are leaks in the process. RTE expressed some reservations about using anhydrous ammonia for this reason.
- Propane. This refrigerant is common in gas treatment facilities, and can be used in CO_2 liquefaction as well. Propane is flammable, and propane refrigeration systems require the instrumentation and other electrical components near the process to be rated for flammable gases, which will represent an increased capital cost. Propane may be slightly less efficient than ammonia in this service, which will increase operating costs.

- R404A. This refrigerant is a mixture of other refrigerants including R125, R134a, and R143a. It is being phased out of the United States and was not pursued further for this project.
- R507A. This refrigerant is a mixture of other refrigerants, and is in common use in low temperature refrigeration applications. The R507a refrigerant has a substantially higher purchase cost than propane or ammonia, and is more prone to be leaked to atmosphere than those refrigerants, which makes operating costs higher than expected.

Ultimately, RTE chose to use anhydrous ammonia as the refrigerant for this process after considering the options above.

5.2 Recycle Dryer Regeneration Gas

A slip stream of dehydrated gas (5-10% of the feed flowrate) is used to regenerate the offline dryer vessel, as described above in Section 4.2. The regeneration gas is saturated with water and can be recycled back to the feed of the compressor or vented to atmosphere. Recycling the regeneration gas means a higher compressor horsepower and electricity cost as well as the additional capital cost of a cooler and separator. Venting the regeneration gas generally means the loss of 5-10% of the feed gas to atmosphere. Both options were considered in this project to determine which was the best for the RTE design.

RTE decided to move forward with recycling the regeneration gas due to an estimated reduction of about 3.0 kWh/tonne of CO_2 produced. Additional capital costs for the slightly increased size of the CO_2 compressor, the presence of a regeneration cooler and regeneration separator do materially affect the capital cost of the entire facility.

5.3 Electrical Requirements

Brake horsepower and operating kW estimates for most of the electrical equipment in the facility are shown below in Table 6.

Table 6. Equipment Generating Electrical Loads for the Potential Liquefaction Facility.

Equipment	P&ID	Description
B-102	PID-10002	CO_2 Inlet Blower
C-201	PID-10005	CO_2 Compressor
C-601	PID-10016	NH_3 Compressor
P-101	PID-10002	Blower Inlet Separator Pump
P-203	PID-10005	CO_2 Compressor Oil Pump
E-306	PID-10009	Dryer Regeneration Heater
P-404A	PID-10012	CO_2 Column Feed Pump
P-404B	PID-10012	CO_2 Column Feed Pump
P-501	PID-10014	CO_2 Booster Pump
P-502	PID-10014	CO_2 Injection Pump
P-503	PID-10014	CO_2 Loading Pump
P-603	PID-10016	NH_3 Compressor Oil Pump
F-700	PID-10019	Cooling Tower Fan
P-701A	PID-10019	Cooling Water Circulation Pump
P-701B	PID-10019	Cooling Water Circulation Pump

Total electrical demand for the liquefaction facility is estimated at 3,900 kW, for a total electricity demand of about 150 kWh/tonne of CO_2 produced.

5.4 Cooling Water Requirements

The RTE liquefaction facility will use cooling water in heat exchangers not using refrigerant. A new cooling tower will be required for the project, and the estimated cooling water circulation flow rates for the liquefaction facility are shown below in Table 7. RTE requested a maximum allowed temperature rise of 12 °F for the cooling water and set the maximum cooling water supply temperature to 82 °F.

Table 7. Equipment Requiring Cooling Water for the Potential Liquefaction Facility.

Equipment	P&ID	Description
E-103	PID-10003	CO_2 Blower Aftercooler
E-204	PID-10005	CO_2 Compressor Lube Oil Cooler
E-300	PID-10007	CO_2 Compressor Aftercooler
E-604	PID-10016	NH_3 Compressor Lube Oil Cooler
E-607	PID-10005	NH_3 Condenser

Total estimated cooling water requirements for the liquefaction facility are 22.0 MMBTU/hr in heat exchanger duty, and about 3,600 gpm cooling water circulation rate.

5.5 Waste Water Requirements

The liquefaction facility will generate several liquid water streams as the CO_2 feed gas is compressed, cooled, and dehydrated. The water streams may be contaminated with small amounts of compressor lubrication oil, alcohols carried over from the RTE CO_2 Scrubber, or other minor contaminants from the gas stream. RTE will need to determine if this water can be recycled in their process or if it should be disposed of directly. An estimate of the waste water sources for the liquefaction facility is shown in Table 8.

Table 8. Equipment Generating Waste Water for the Potential Liquefaction Facility.

Equipment	P&ID	Description	Potential Contaminants
V-100	PID-10002	Blower Inlet Separator	Scrubber Carryover
V-104	PID-10003	Blower Aftercooler Separator	None
V-200	PID-10004	CO_2 Compressor Inlet Separator	None
V-301	PID-10007	Aftercooler Separator	Compressor Oil
V-303	PID-10008	Refrigerant Aftercooler Separator	Compressor Oil
T-700	PID-10019	Cooling Tower Blow Down	High Conductivity

Total estimated waste water requirements for the liquefaction facility are about 9 gpm of water.

5.6 Process Water Requirements

The new cooling tower will need make up water continuously, but that will be the only constant demand for process water. The NH_3 Vent Header Tank will periodically need water as well, but this should be a minor requirement and only require water occasionally. Total process water needs for the liquefaction facility are shown in Table 9.

Table 9. Equipment Requiring Process Water for the Potential Liquefaction Facility.

Equipment	P&ID	Description	Operation
T-700	PID-10019	Cooling Tower Make Up	Continuous
TK-702	PID-10020	NH3 Vent Header Tank	Intermittent

Total estimated process water requirements for the liquefaction facility are about 57 gpm of water.

5.7 Miscellaneous Utility Requirements

In addition to the utilities noted above, the liquefaction facility will use saturated steam in the E-502 CO_2 Product Heater and instrument air throughout the facility. Estimates for this utility usage are shown in Table 10 and Table 11, respectively.

Table 10. Equipment Requiring Steam for the Potential Liquefaction Facility.

Equipment	P&ID	Description
E-502	PID-10014	CO_2 Product Heater

Table 11. Equipment Requiring Instrument Air for the Potential Liquefaction Facility.

Equipment	Quantity	Notes
Pneumatic Valves	44	Estimate of 40 SCFH per Valve
Panel Purges	0	Estimate of 10 SCFH per Panel

6 Capital Cost Estimate

As part of this project, Trimeric developed a request for quotation (RFQ) and issued the RFQ to three separate reputable companies that design and manufacture equipment for liquid CO_2 production.

The average purchased equipment cost for the three bids received from the companies was $10.7 million dollars, which excludes the expected costs of the storage tanks. Additional costs for installation, storage tanks, and freight are shown in Table 12. There is also no contingency included in this estimate, interest rates, or other costs that may be expected on a project of this size and complexity.

Table 12. Estimated Capital Cost for Liquefaction Facility with Manufacturer Bids.

Purchased Equipment Cost (Excluding Storage Tanks)	$10,700,000
Expected Installation Costs (Excluding Storage Tanks)	$6,300,000
Storage Tank Total Installed Cost	$2,600,000
Freight Costs (Excluding Storage Tanks)	$170,000
Total Installed Cost Estimate	$19,770,000

Liquid CO_2 storage tanks are large vessels, heavily insulated, and operate at a high pressure for a vessel that is so large. Freight and installation costs for the liquid CO_2 storage costs are substantial, and feedback from one of the equipment manufacturers on this project was that a total installed cost for a single storage tank could be as high as $1,300,000. Vendor equipment purchased cost estimates include the cost for the motor control centers. Installation costs for the other equipment in the facility are based upon the modular construction of the entire facility, and that the required fieldwork once the equipment is on-site and installed on foundations is minimal.

7 Cost Mitigation Opportunities

The CO_2 liquefaction unit designed in this project contains a number of assumptions that impact the overall capital cost of the facility and the overall operating cost of the facility. Some of these options are covered in this section, and should be investigated further during the detailed design phase of the project.

7.1 Liquid CO_2 Storage Tanks

The primary objective of capturing the CO_2 vented at the RTE facility is to sequester the CO_2 in a geologic formation to realize federal and state level tax credits and CO_2 credits. There may be opportunities in the future to sell or buy CO_2 to or from third parties as a truck or rail liquid product, but those opportunities are not being realized at this stage of the project. If bulk storage of liquid CO_2 is not required, and the liquid CO_2 product could be injected directly from the liquefaction facility, the liquid CO_2 storage tanks (TK-500A/B) would not be required for this project and could reduce the total project costs by $2,600,000. Figure 1 shows a block diagram of this concept. Connections for liquid storage tanks could be provided initially and then the tanks could be installed if the anticipated third party sales or purchases were realized.

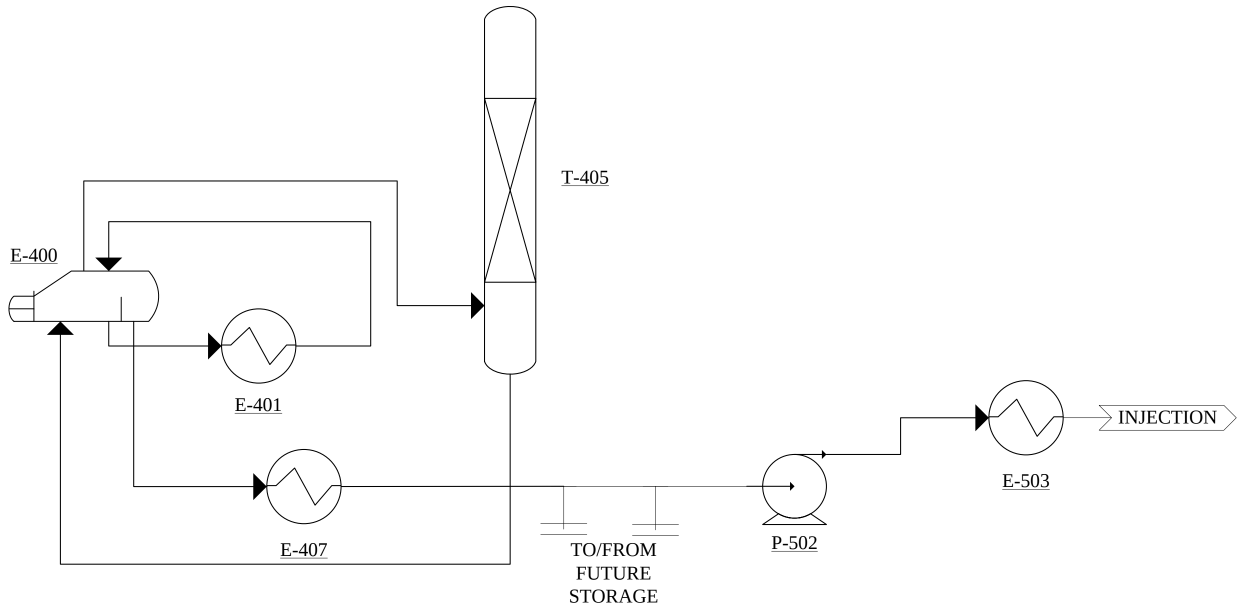


Figure 1. Product CO_2 Configuration Without Storage Tanks.

7.2 E-503 CO_2 Product Heater Heat Medium Change

Per the current design, the E-503 CO_2 Product Heater will heat the product CO_2 with saturated steam. One of the manufacturers contacted for this project suggested using liquid ammonia to heat the CO_2 stream; this would allow the refrigeration system to operate more efficiently since the liquid ammonia would be further subcooled, and ultimately reduce the amount of ammonia circulated in the refrigeration system. In this option, the liquefaction facility would need to be running in order to meet the temperature requirement on the discharge of the facility, so injection could not continue if the liquefaction facility shut down for maintenance or another reason. If RTE needs to continue injecting for some reason while the liquefaction facility is offline, the saturated steam heating medium may be the preferred option.

7.3 E-607 NH_3 Condenser Design and Approach Temperature

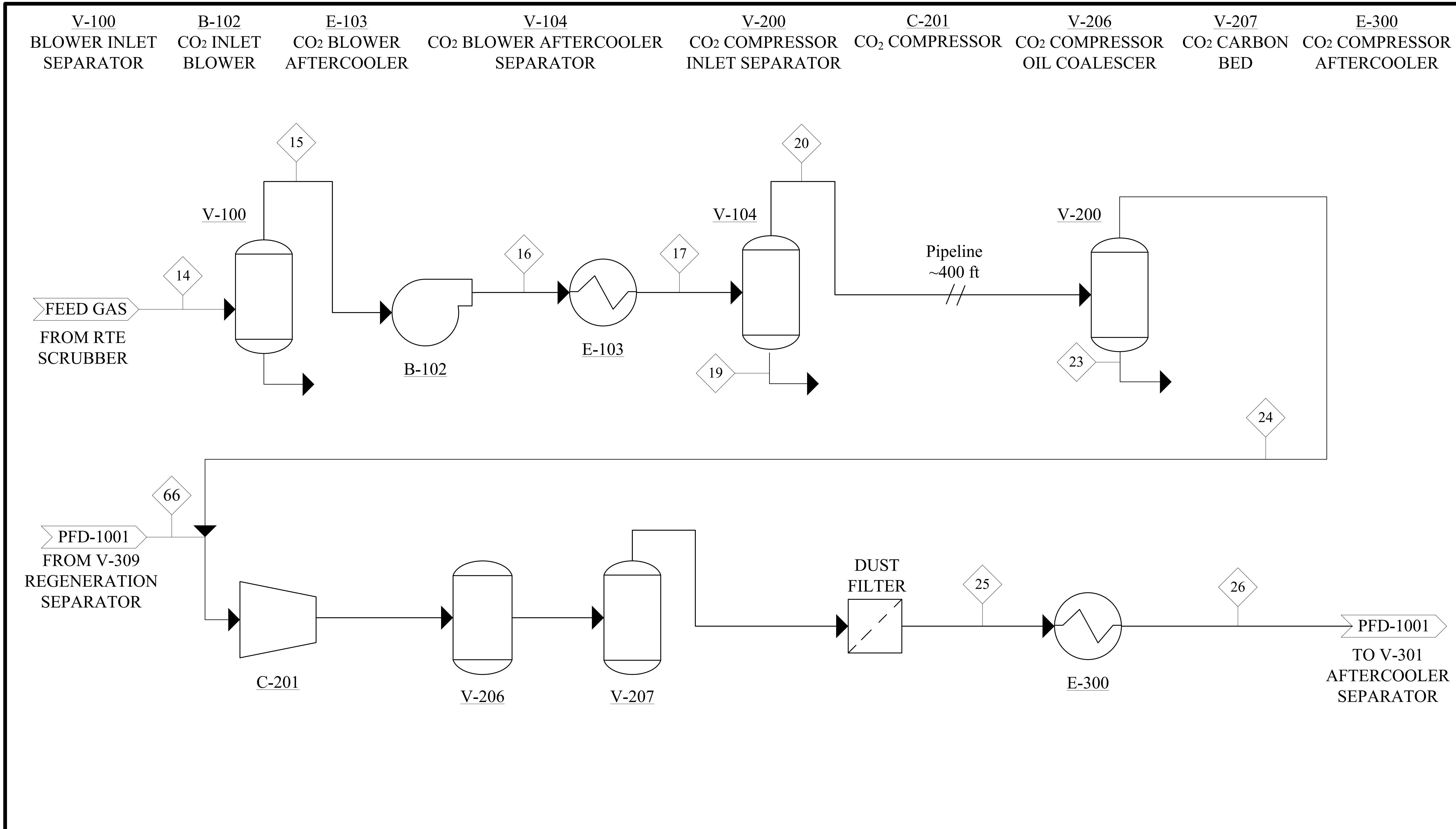
As discussed above, the condensation temperature of the ammonia in the refrigeration system is a key design point. The higher the condensation temperature of the ammonia, the more horsepower will be required for the C-601 NH_3 Compressor. As a result, the lowest operating cost for the facility will be achieved by condensing the ammonia refrigerant at a temperature as close to the wet bulb temperature as practical. One manufacturer proposed a wet surface air cooler for the E-607 NH_3 Condenser, which is a hybrid cooling tower design where a thin film of water is sprayed over the exchanger tubes while air is forced over the condenser tube banks. This design minimizes the condensation temperature of the ammonia, but costs an additional

$400,000 of upfront capital investment. Further work would be required to determine if this additional cost is justified for the reduction in operating costs.

Trimeric expects that the cooling water supply temperature of 82 °F will be easily achieved for most of the year at RTE's facility in North Dakota, and that the process will operate more efficiently than estimated for much of the year in any event.

APPENDIX A

PROCESS FLOW DIAGRAMS



PRELIMINARY – NOT FOR CONSTRUCTION

REVISIONS						
REV	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
0	3/21/19	Draft for EERC Review	AEV	BDP		
1	4/26/19	Revised equipment tags and names	AEV	BDP		
2	05/29/19	Revise for RFQ	BDP			

TRIMERIC CORPORATION
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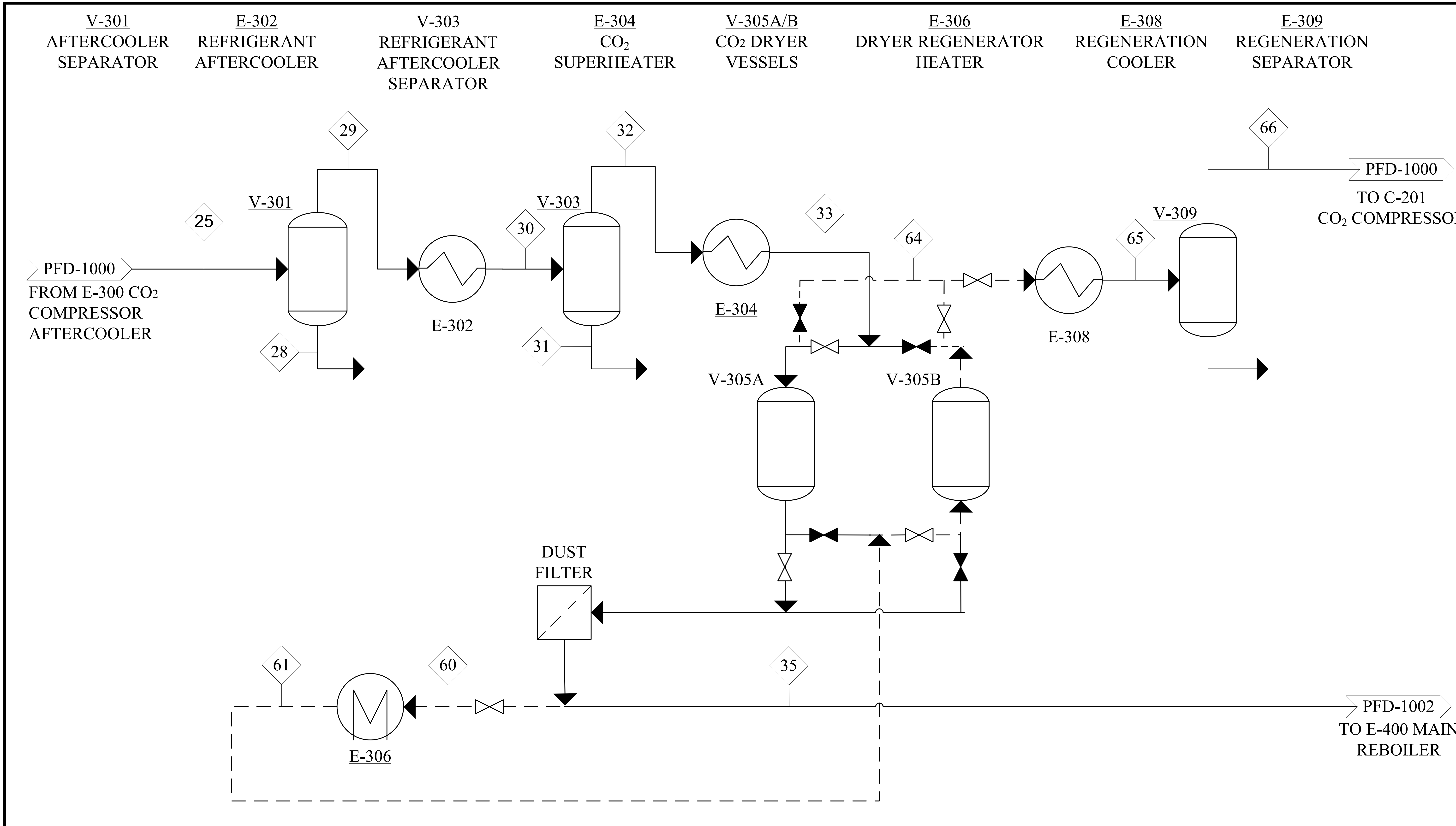
Buda, Texas 78610

EERC Ph. III
FEED COMPRESSION

FILENAME EERC P3 PFD 091819.VSD	DATE		DRAWN BY Austyn Vance
CLIENT/SITE	EERC	JOB NUMBER	50168.04
DRAWING NUMBER	PFD-1000	SCALE	NONE



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FILENAME: EERC P3 PFD 091819.VSD | DATE | DRAWN BY: Austyn Vance

REVISIONS

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1	4/26/19	Revised equipment tags and names	AEV	BDP		
2	05/29/19	Revise for RFQ	BDP			

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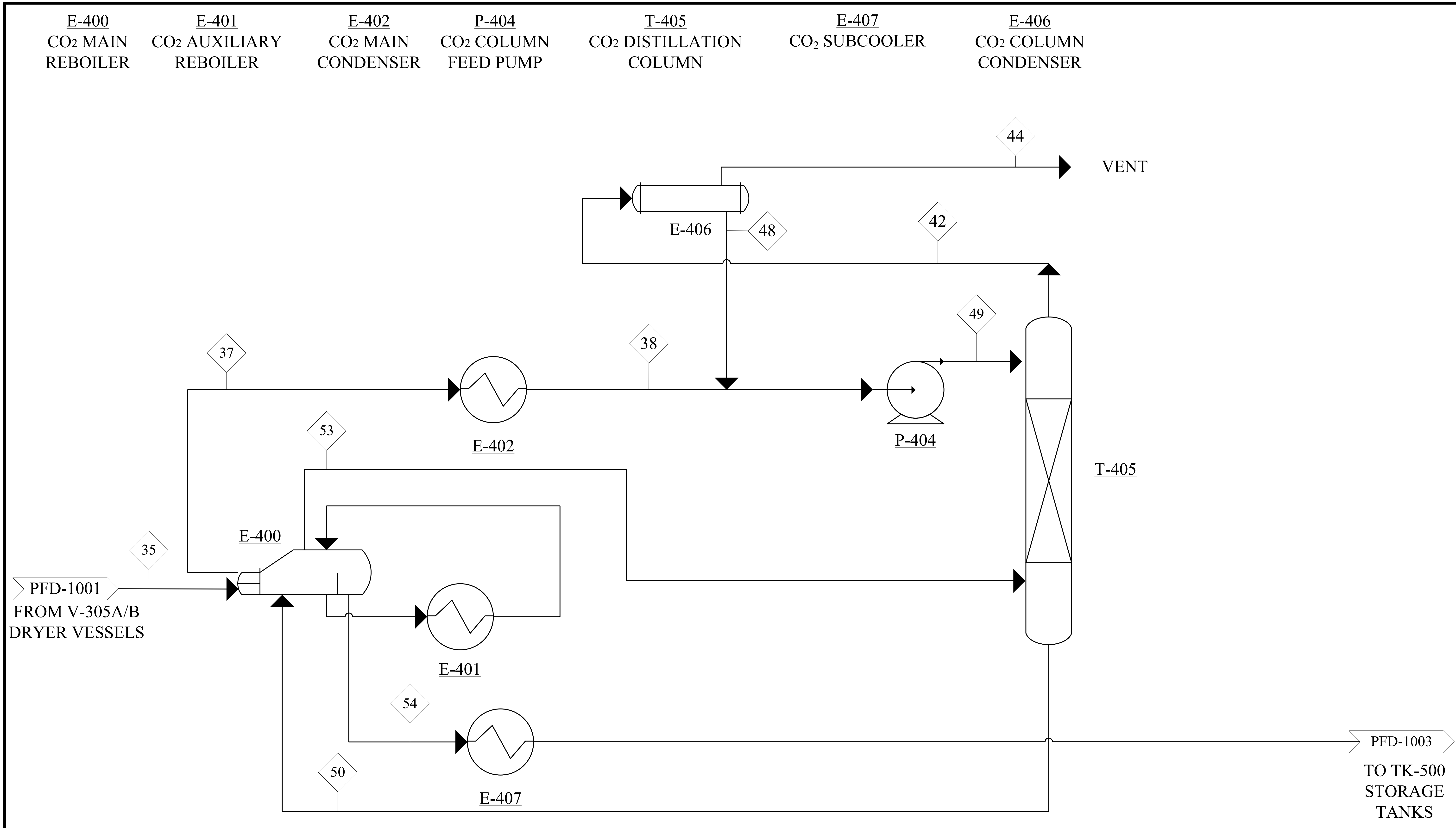
EERC Ph. III COOLING AND DEHYDRATION

CLIENT/SITE: EERC
JOB NUMBER: 50168.04
DRAWING NUMBER: PFD-1001
SCALE: NONE



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REVISIONS

REV	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
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2	05/29/19	Revise for RFQ	BDP			

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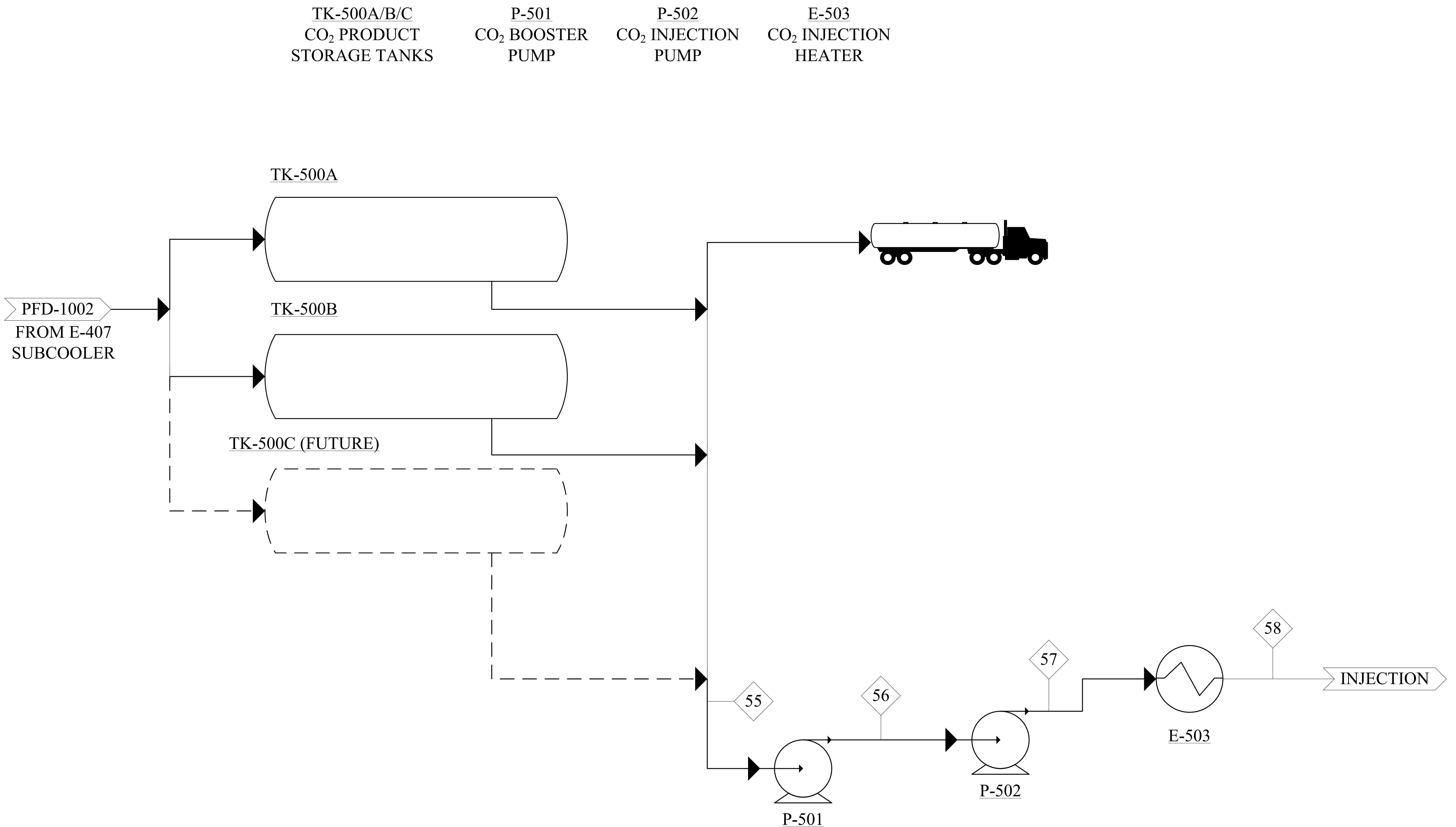
EERC Ph. III LIQUEFACTION AND DISTILLATION

CLIENT/SITE EERC | JOB NUMBER 50168.04
DRAWING NUMBER PFD-1002 | SCALE NONE



PRELIMINARY – NOT FOR CONSTRUCTION

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REVISIONS

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1	4/26/19	Revised equipment tags and names	AEV	BDP		
2	05/29/19	Revise for RFQ	BDP			

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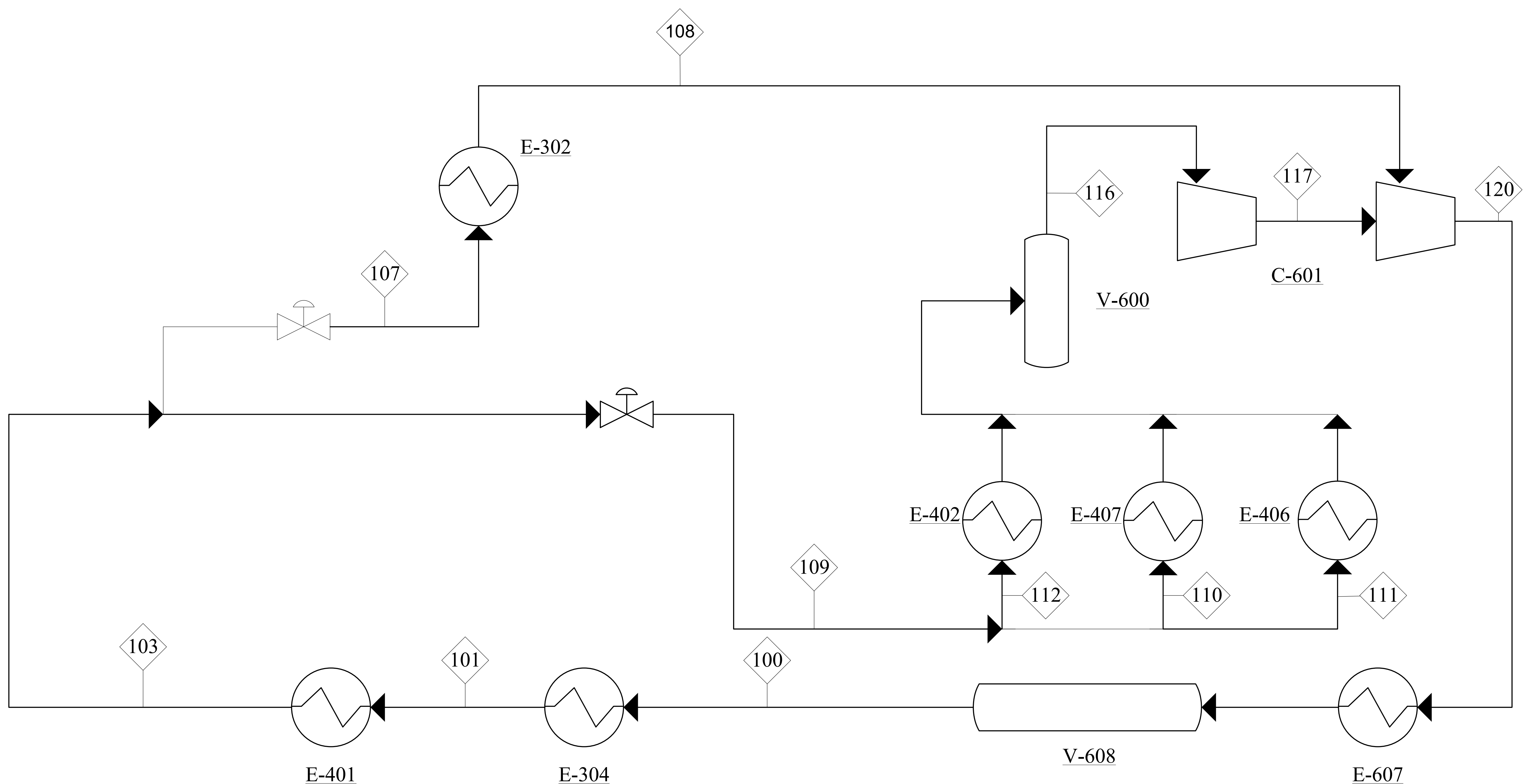
EERC Ph. III
STORAGE AND INJECTION

CLIENT/SITE EERC | JOB NUMBER 50168.04
DRAWING NUMBER PFD-1003 | SCALE NONE

E-402	E-407	E-406	E-401	E-304	C-601	V-600	E-302	VE-1	V-608	E-607
CO_2 MAIN CONDENSER	CO_2 SUBCOOLER	CO_2 COLUMN CONDENSER	CO_2 AUXILIARY REBOILER	CO_2 SUPERHEATER	NH_3 COMPRESSOR	AMMONIA SEPARATOR	REFRIGERANT AFTERCOOLER	AMMONIA ECONOMIZER	NH_3 RECEIVER	NH_3 CONDENSER



PRELIMINARY – NOT FOR CONSTRUCTION

FILENAME: EERC P3 PFD 091819.VSD
DATE
DRAWN BY: Austyn Vance

REVISIONS

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2	05/29/19	Revise for RFQ	BDP			

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EERC Ph. III
AMMONIA REFRIGERATION

CLIENT/SITE: EERC
JOB NUMBER: 50168.04
DRAWING NUMBER: PFD-1004
SCALE: NONE

APPENDIX B

PRELIMINARY P&IDs

LINE IDENTIFICATION

NOMINAL SIZE — LINE NUMBER — INSULATION

24"-CO2V-11452-150CS-IC

SERVICE — PIPE SPEC

SERVICE CODES	
CO2V	VAPOR CARBON DIOXIDE
CO2L	LIQUID CARBON DIOXIDE
NH3V	VAPOR AMMONIA
NH3L	LIQUID AMMONIA
CWS	COOLING WATER SUPPLY
CWR	COOLING WATER RETURN
PW	PROCESS WATER
WW	WASTE WATER
LPS	LOW PRESSURE STEAM
CND	STEAM CONDENSATE

PIPE SPECIFICATION	
150CS	CARBON STEEL 150#
300CS	CARBON STEEL 300#
600CS	CARBON STEEL 600#
900CS	CARBON STEEL 900#
150SS	STAINLESS STEEL 150#
300SS	STAINLESS STEEL 300#
600SS	STAINLESS STEEL 600#
900SS	STAINLESS STEEL 900#

INSULATION CODES	
0	NONE
IC	COLD CONSERVATION
IH	HEAT CONSERVATION
PP	PERSONNEL PROTECTION
FP	FREEZE PROTECTION

VALVES	
	CONTROL VALVE
	ON/OFF VALVE
	BALL VALVE
	GATE VALVE
	BUTTERFLY VALVE
	GLOBE VALVE
	3-WAY VALVE

DEVICES AND MISCELLANEOUS	
	SCOPE BREAK
	SPECTACLE BLIND, OPEN
	WYE STRAINER
	PRESSURE RELIEF VALVE
	RUPTURE DISK
	CHECK VALVE
RO	RESTRICTION ORIFICE
FE	ORIFICE METER
F	ROTAMETER
	DRAIN TO SUMP
T	STEAM TRAP
	HOSE

VALVE FAILURE POSITION	
FC	FAIL CLOSED
FO	FAIL OPEN
FL	FAIL LAST

INSTRUMENT AND CONTROL LETTERS

	FIRST LETTER		SUCCEEDING LETTERS		
	MEASURED	MODIFIER	READOUT	OUTPUT	MODIFIER
A	ANALYSIS		ALARM		
B	BURNER				
C				CONTROL	
D		DIFFERENTIAL			
E	VOLTAGE		ELEMENT		
F	FLOW	RATIO			
G	ACCEL		GAUGE		
H	HAND				HIGH
I	CURRENT		INDICATE		
J	POWER	SCAN			
K	TIME	TIME ROC			
L	LEVEL		LIGHT		LOW
M		MOMENTARY			
N					
O			ORIFICE		
P	PRESSURE				
Q	QUANTITY	TOTALIZE			
R	RADIATION				
S	SPEED	SAFETY		SWITCH	
T	TEMPERATURE			TRANSMITTER	
U	UNDEFINED		UNDEFINED	UNDEFINED	UNDEFINED
V	VIBRATION				
W	WEIGHT				
X	UNDEFINED		UNDEFINED	UNDEFINED	UNDEFINED
Y	EVENT			RELAY	
Z	POSITION			FINAL CONTROL	

INSTRUMENT AND CONTROL SYMBOLS

SYMBOL	DESCRIPTION	LOCATION
	FIELD MOUNTED	FIELD
	PANEL MOUNTED, ACCESIBLE	CONTROL PANEL
	COMPUTER SCREEN, ACCESIBLE	HMI (HMI/DCS)
	COMMS SIGNAL	CONTROL PANEL

LINE DEFINITIONS

	PROCESS
	CAPILLARY
	PNEUMATIC
	ELECTRIC
	DATA

EQUIPMENT IDENTIFICATION

EQUIPMENT TYPE — PLANT AREA

X – X XX

UNIQUE NUMBER

EQUIPMENT TYPE	
B	CENTRIFUGAL BLOWER
C	COMPRESSOR
E	EXCHANGER
P	PUMP
T	TOWER
TK	TANK
V	VESSEL

PLANT AREA	
1	INLET BLOWER
2	COMPRESSION
3	COOLING AND DEHYDRATION
4	LIQUEFACTION AND DISTILLATION
5	PRODUCT STORAGE AND INJECTION
6	REFRIGERATION
7	UTILITIES

PRELIMINARY – NOT FOR CONSTRUCTION

REVISIONS						
REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
0	04/17/2019	ISSUED FOR REVIEW	BDP			

FILENAME: EERC_P&IDS_REV0.VSD | DATE: 04/17/2019 | DRAWN BY: BRAD PIGGOTT

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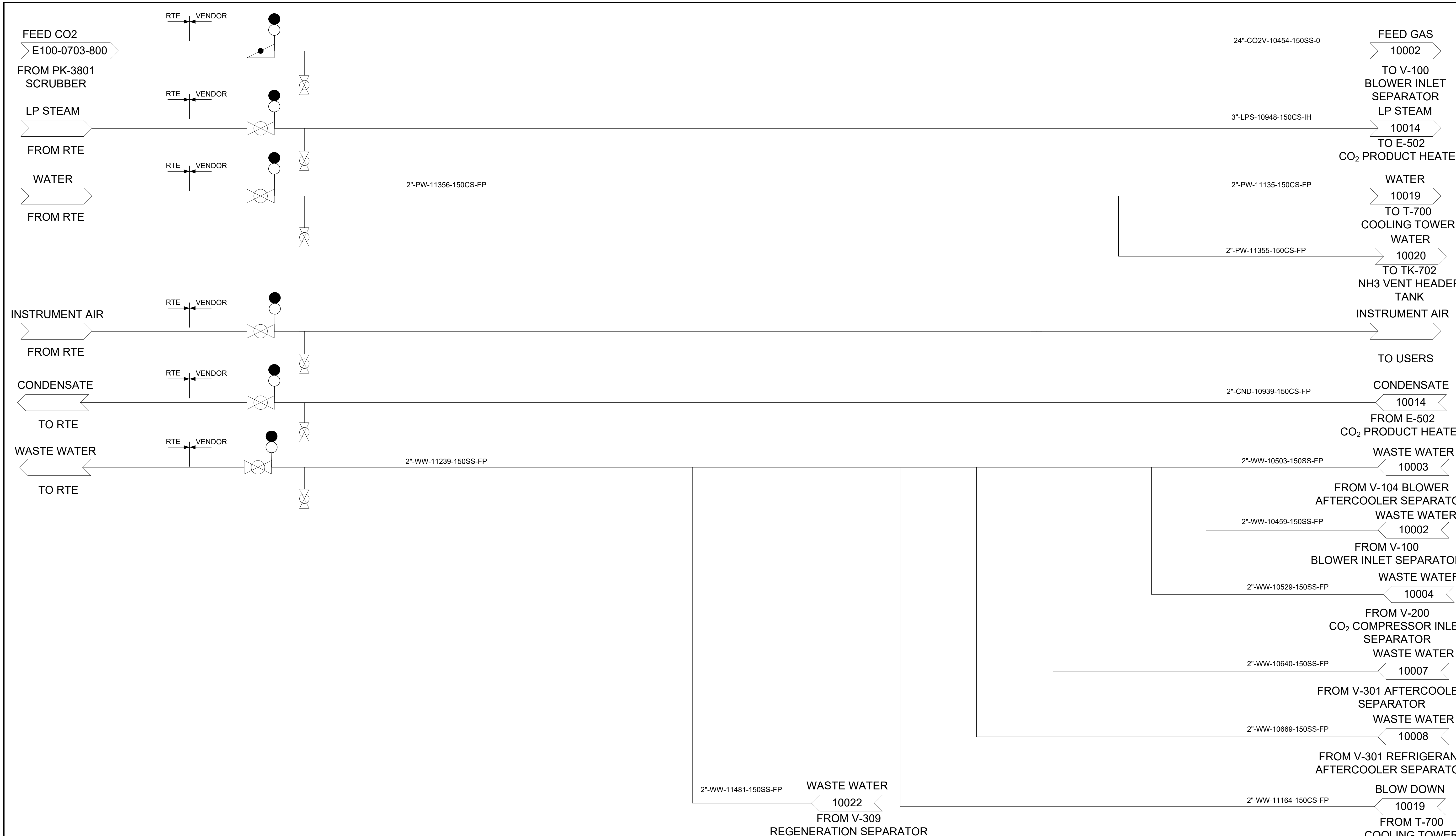
P.O. Box 826
Buda, Texas 78610

EERC – RTE CO_2 INJECTION FACILITY LEGEND

CLIENT/SITE: EERC / RTE ETHANOL RICHARDTON, ND | JOB NUMBER: 50168.04

DRAWING NUMBER: PID-00000 | SCALE: NONE



PRELIMINARY – NOT FOR CONSTRUCTION

REVISIONS

REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
0	04/17/2019	ISSUED FOR REVIEW	BDP			

FILENAME EERC_P&IDS_REV0.VSD | DATE 04/17/2019 | DRAWN BY BRAD PIGGOTT

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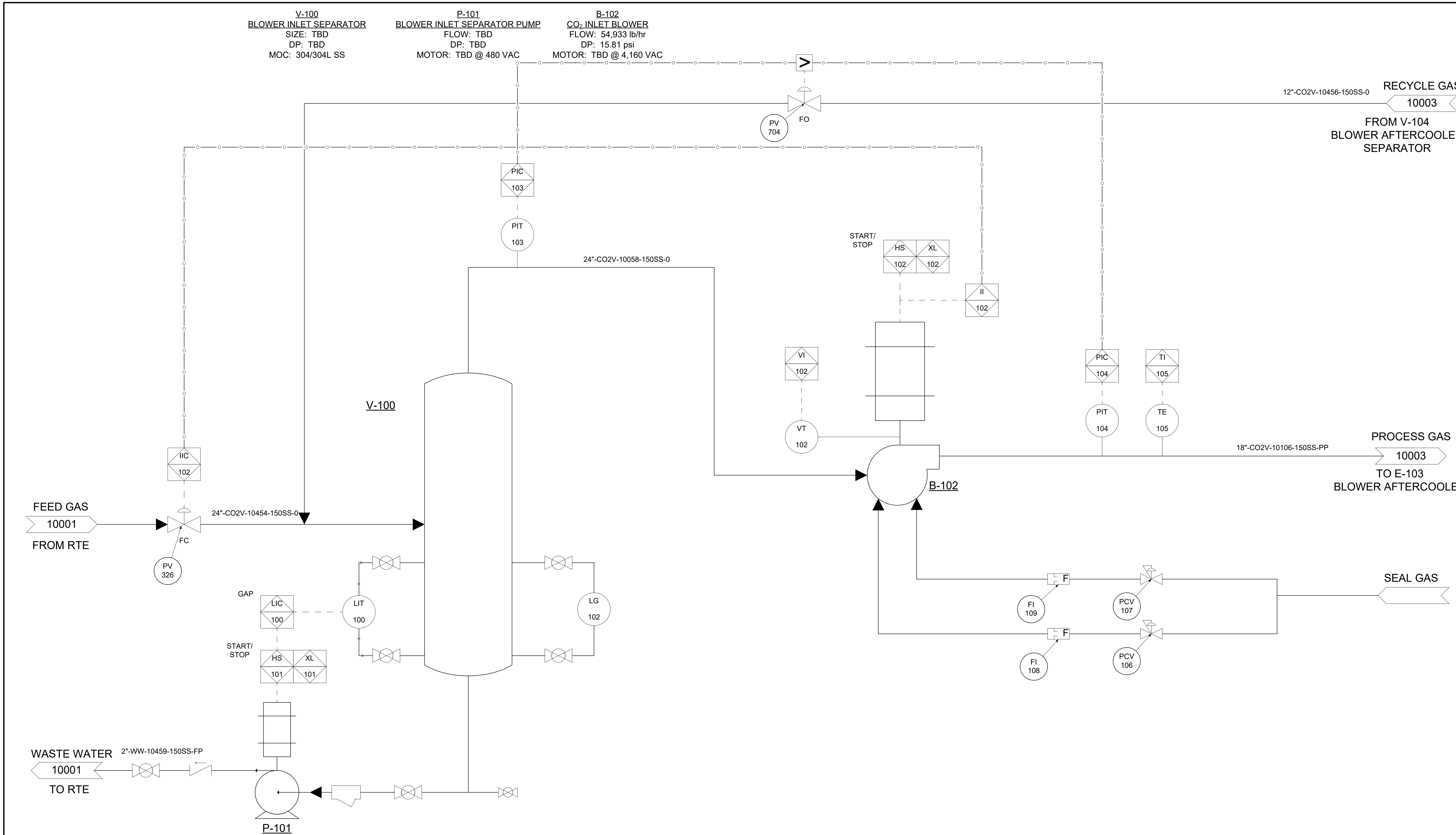
EERC – RTE CO_2 INJECTION FACILITY
BATTERY LIMITS

CLIENT/SITE EERC / RTE ETHANOL RICHARDTON, ND
JOB NUMBER 50168.04
DRAWING NUMBER PID-10001
SCALE NONE



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REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
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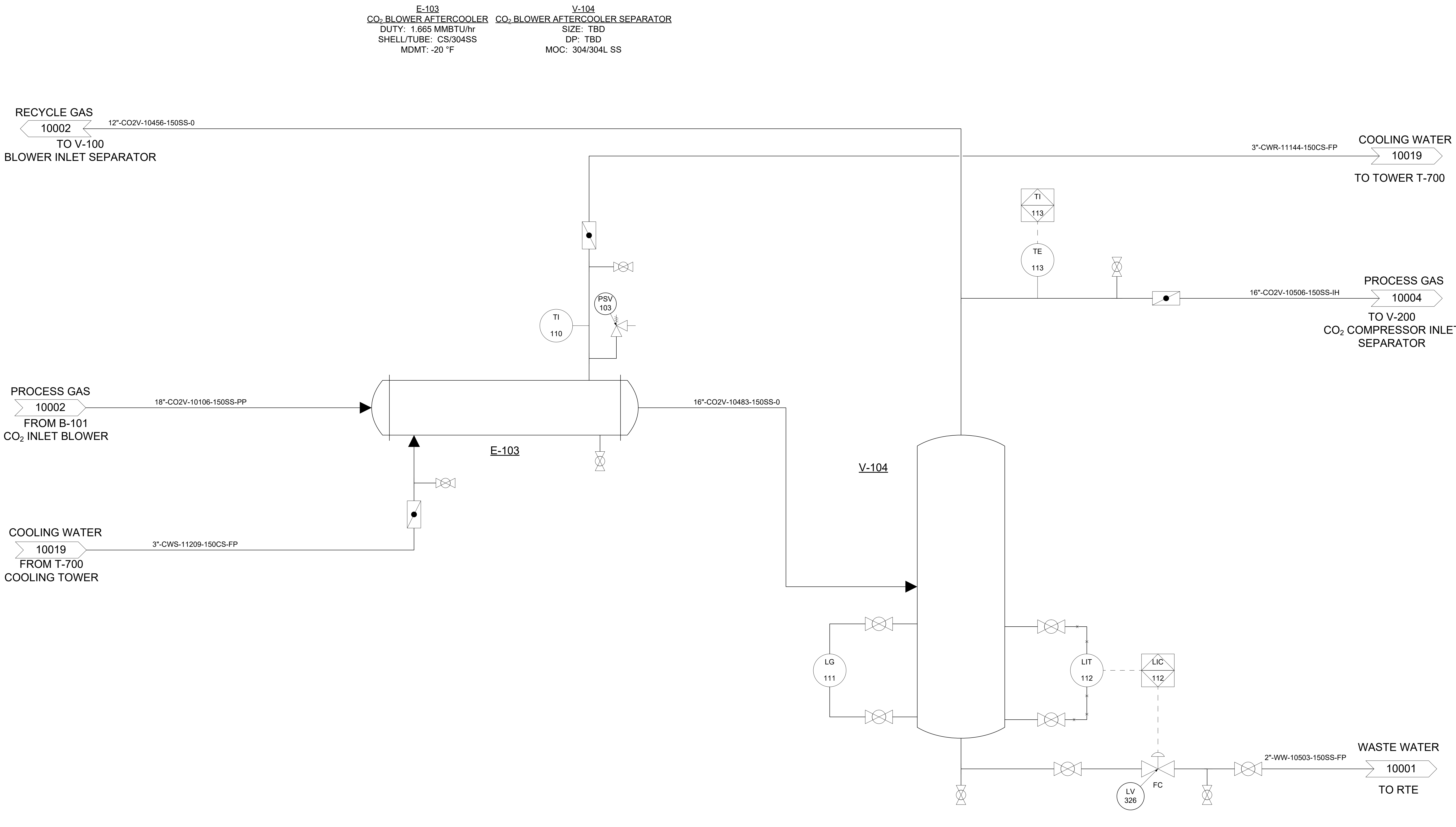
EERC – RTE CO_2 INJECTION FACILITY
CO_2 INLET BLOWER

CLIENT/SITE	JOB NUMBER
EERC / RTE ETHANOL RICHARDTON, ND	50168.04
DRAWING NUMBER	SCALE
PID-10002	NONE



PRELIMINARY – NOT FOR CONSTRUCTION

FILENAME	DATE		DRAWN BY
EERC_P&IDS_REV0.VSD	04/12/2019		BRAD PIGGOTT

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REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
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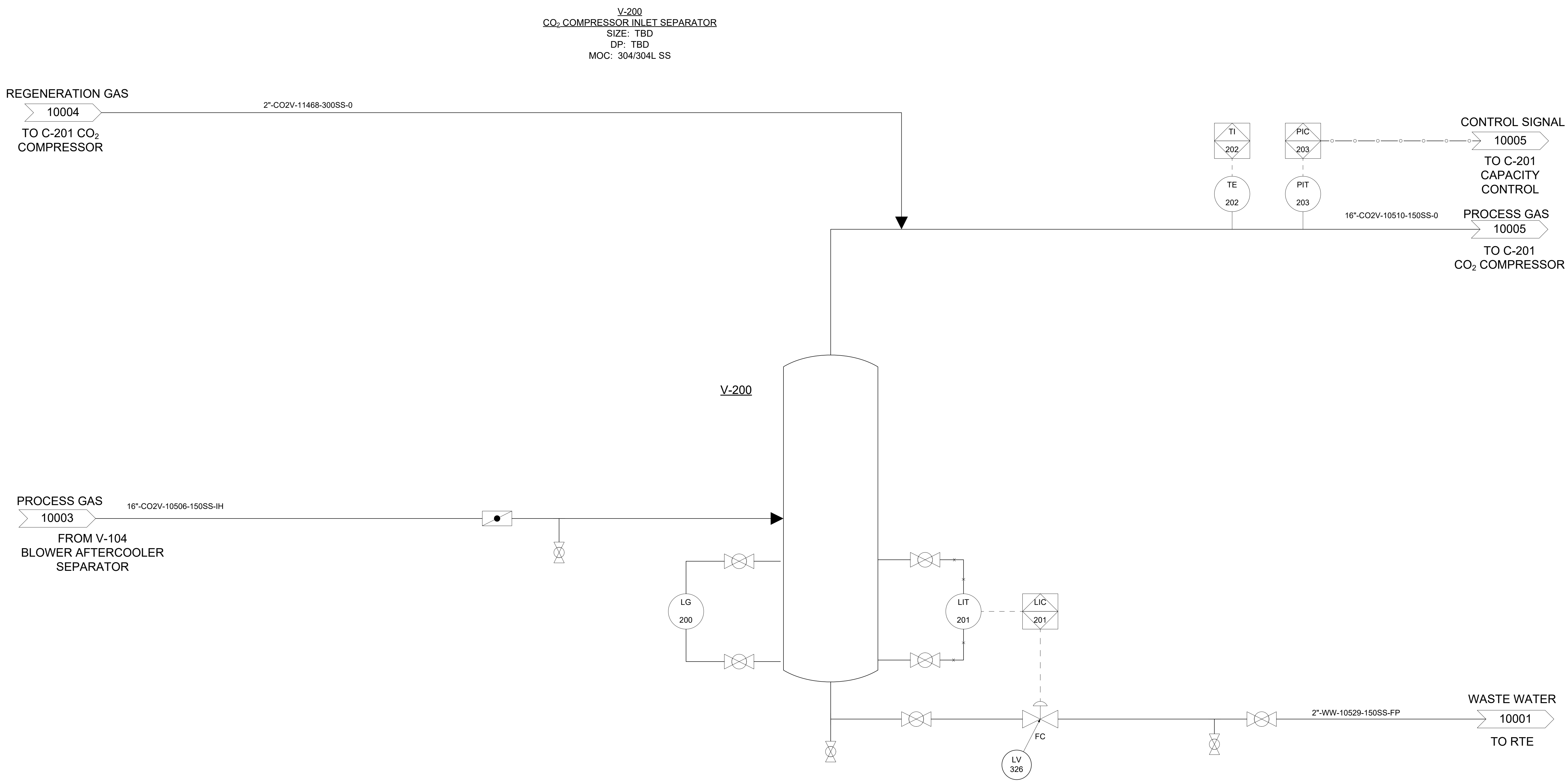
EERC – RTE CO_2 INJECTION FACILITY
BLOWER AFTERCOOLER AND SEPARATION

CLIENT/SITE	JOB NUMBER
EERC / RTE ETHANOL RICHARDTON, ND	50168.04
DRAWING NUMBER	SCALE
PID-10003	NONE



PRELIMINARY – NOT FOR CONSTRUCTION

FILENAME	DATE		DRAWN BY
EERC_P&IDS_REV0.VSD	04/12/2019		BRAD PIGGOTT

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REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
0	04/12/2019	ISSUED FOR REVIEW	BDP			

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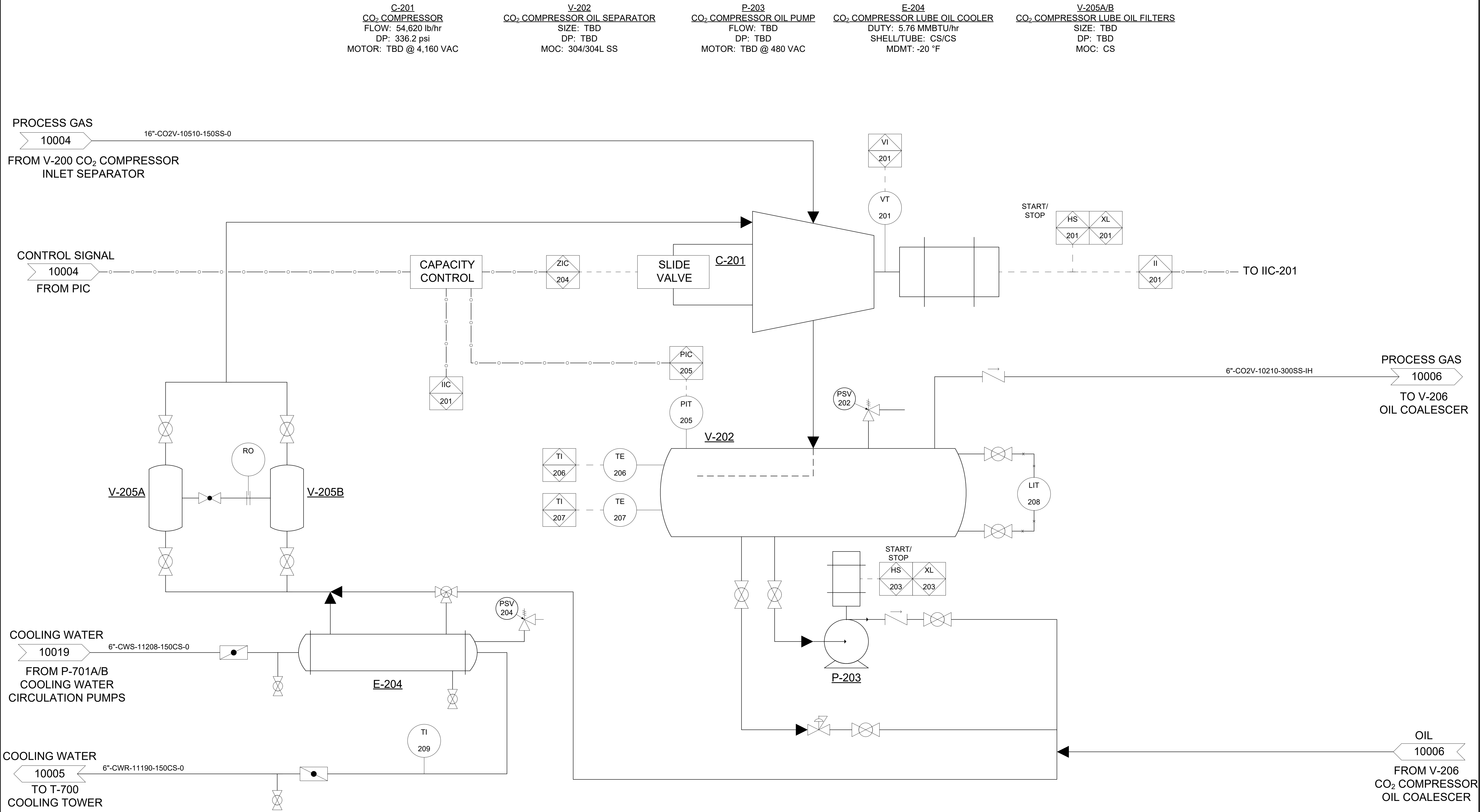
EERC – RTE CO_2 INJECTION FACILITY
COMPRESSOR INLET SEPARATION

CLIENT/SITE	JOB NUMBER
EERC / RTE ETHANOL RICHARDTON, ND	50168.04
DRAWING NUMBER: PID-10004	SCALE: NONE



PRELIMINARY – NOT FOR CONSTRUCTION

FILENAME	DATE		DRAWN BY
EERC_P&IDS_REV0.VSD	04/15/2019		BRAD PIGGOTT

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REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
0	04/15/2019	ISSUED FOR REVIEW	BDP			

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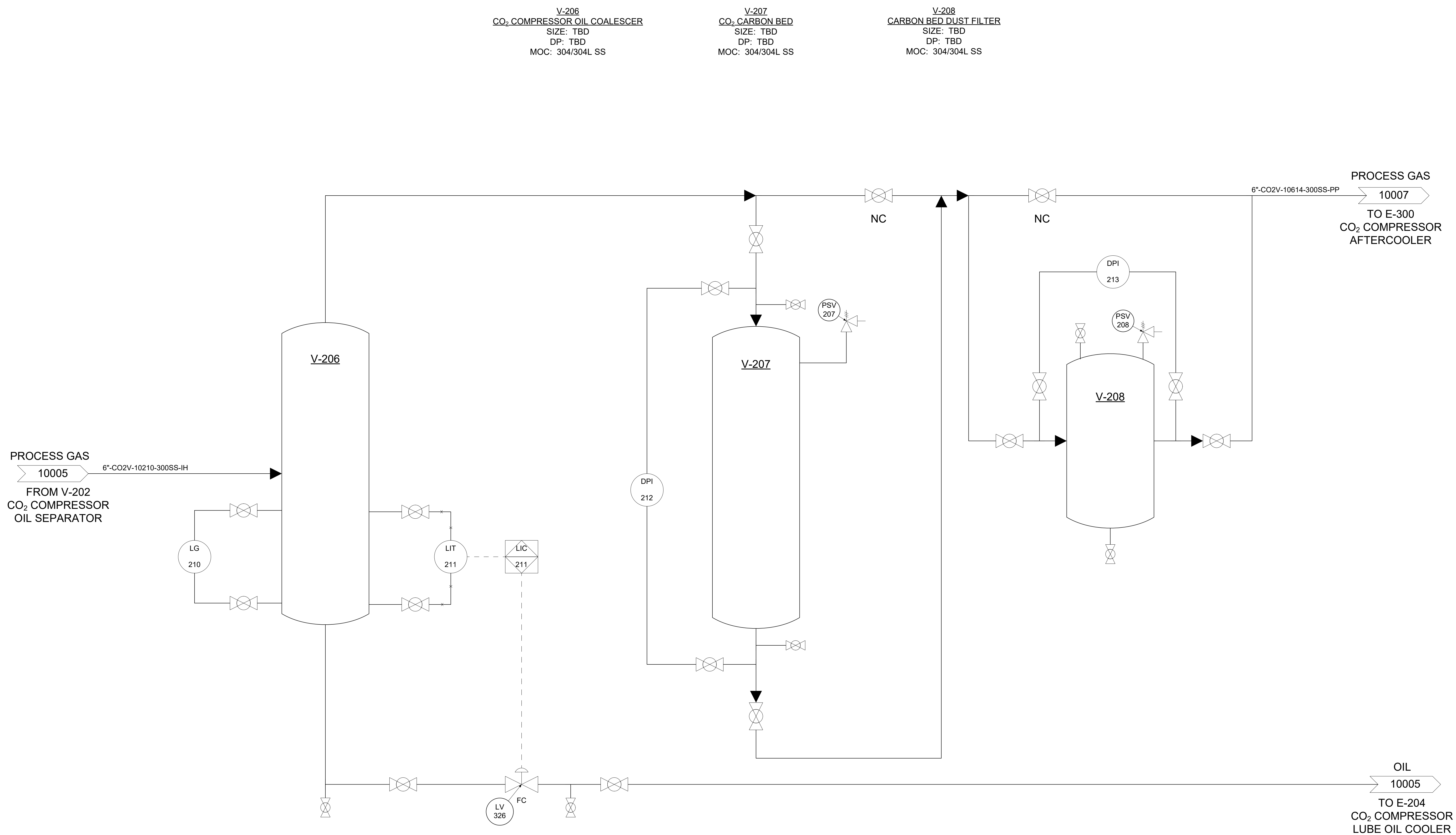
EERC – RTE CO_2 INJECTION FACILITY
CO_2 COMPRESSOR

CLIENT/SITE	JOB NUMBER
EERC / RTE ETHANOL RICHARDTON, ND	50168.04
DRAWING NUMBER	SCALE
PID-10005	NONE



PRELIMINARY – NOT FOR CONSTRUCTION

FILENAME: EERC_P&IDS_REV0.VSD
DATE: 04/15/2019
DRAWN BY: BRAD PIGGOTT

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REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
0	04/15/2019	ISSUED FOR REVIEW	BDP			

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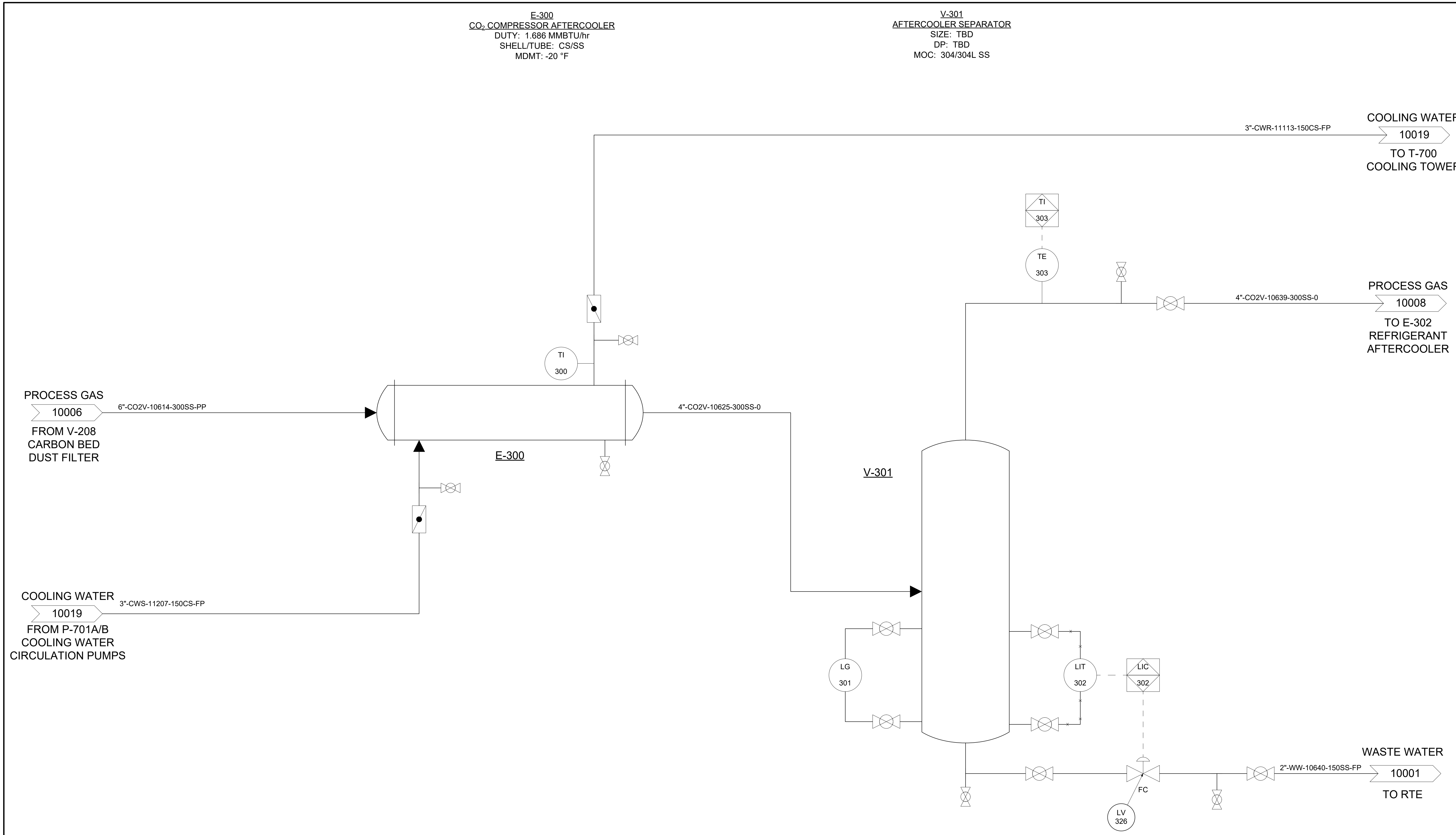
Buda, Texas 78610

EERC – RTE CO_2 INJECTION FACILITY
CO_2 COMPRESSOR OIL POLISHING

CLIENT/SITE: EERC / RTE ETHANOL RICHARDTON, ND
JOB NUMBER: 50168.04
DRAWING NUMBER: PID-10006
SCALE: NONE



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FILENAME	DATE		DRAWN BY
EERC_P&IDS_REV0.VSD	04/15/2019		BRAD PIGGOTT

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REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
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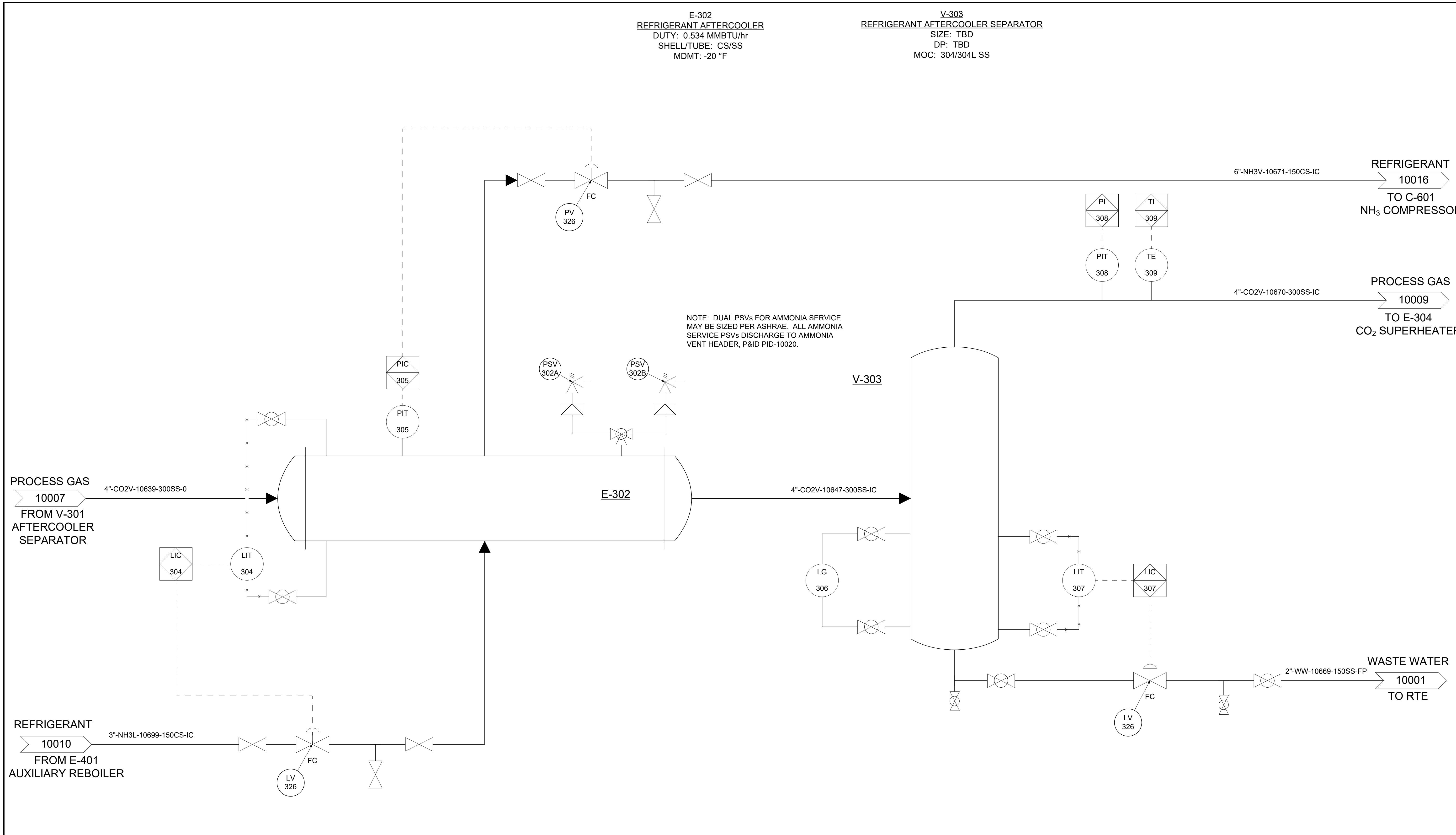
EERC – RTE CO_2 INJECTION FACILITY
CO_2 COOLING

CLIENT/SITE	JOB NUMBER
EERC / RTE ETHANOL RICHARDTON, ND	50168.04
DRAWING NUMBER	SCALE
PID-10007	NONE



PRELIMINARY – NOT FOR CONSTRUCTION

FILENAME	DATE		DRAWN BY
EERC_P&IDS_REV0.VSD	04/15/2019		BRAD PIGGOTT

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REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
0	04/15/2019	ISSUED FOR REVIEW	BDP			

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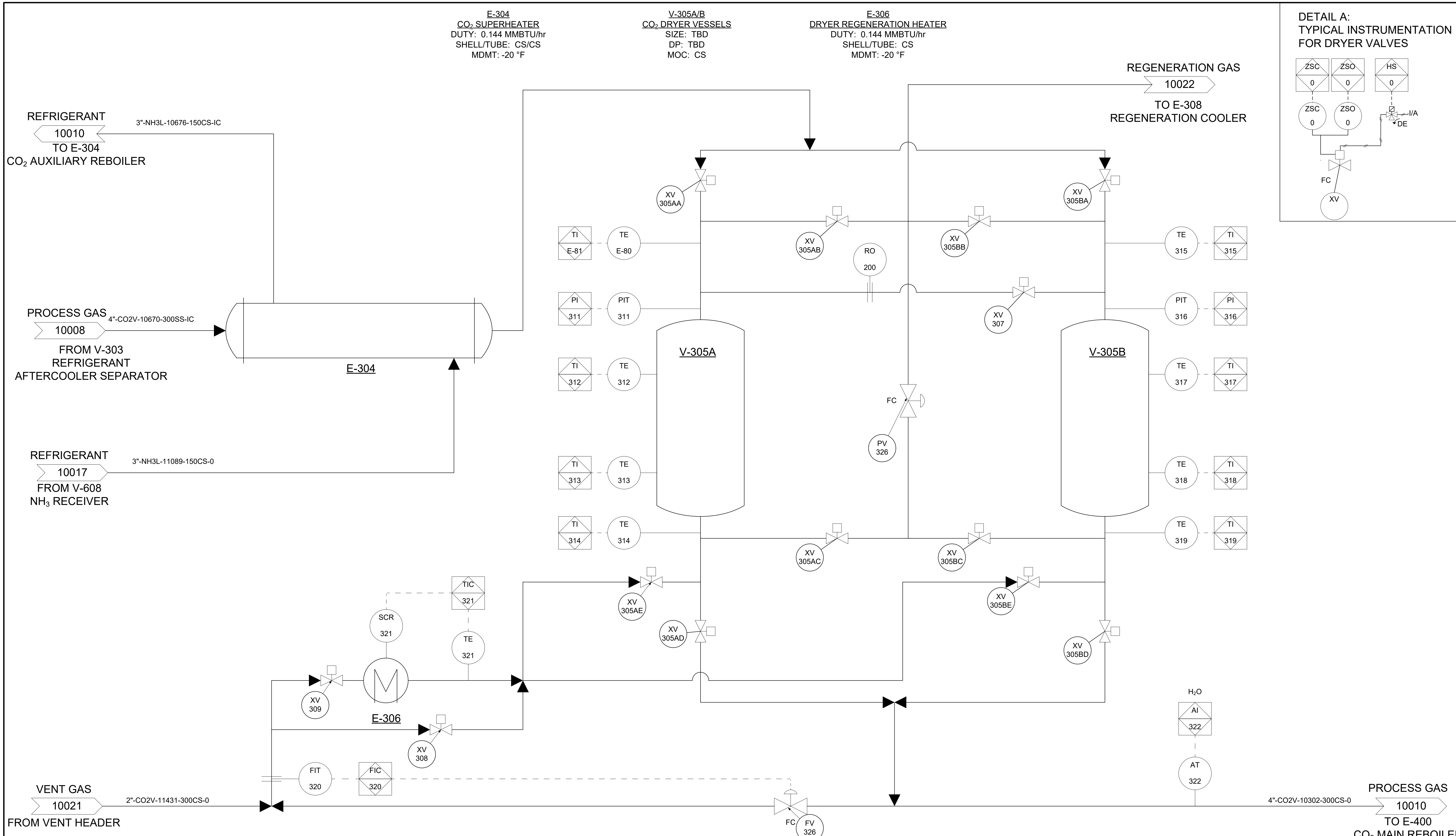
EERC – RTE CO_2 INJECTION FACILITY
CO_2 COOLING

CLIENT/SITE	JOB NUMBER
EERC / RTE ETHANOL RICHARDTON, ND	50168.04
DRAWING NUMBER	SCALE
PID-10008	NONE



PRELIMINARY – NOT FOR CONSTRUCTION

FILENAME	DATE		DRAWN BY
EERC_P&IDS_REV0.VSD	04/15/2019		BRAD PIGGOTT

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REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
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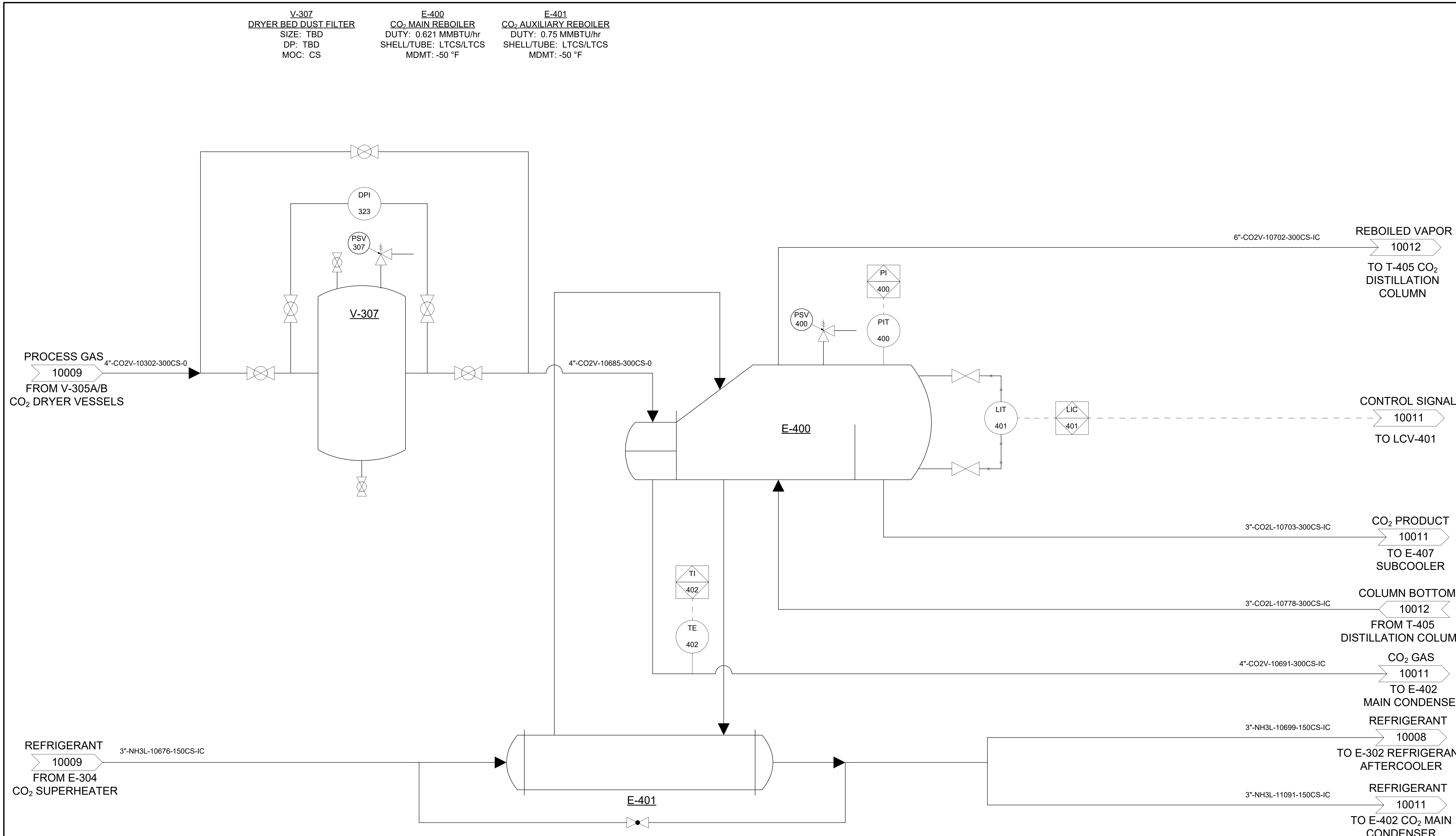
EERC – RTE CO_2 INJECTION FACILITY
CO_2 DEHYDRATION

CLIENT/SITE	JOB NUMBER
EERC / RTE ETHANOL RICHARDTON, ND	50168.04
DRAWING NUMBER	SCALE
PID-10009	NONE



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0	04/12/2019	ISSUED FOR REVIEW	BDP			

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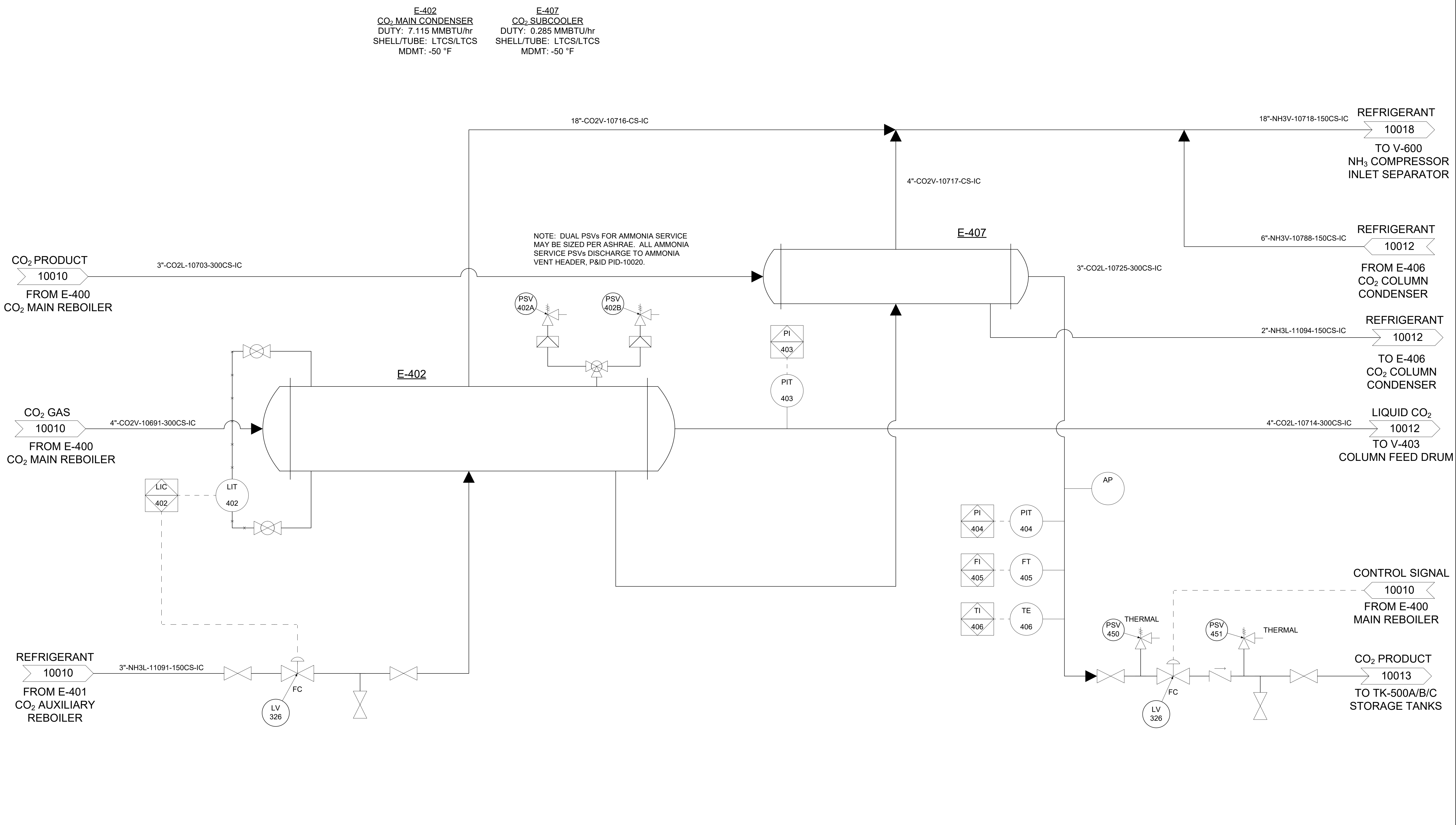
Buda, Texas 78610

EERC – RTE CO_2 INJECTION FACILITY
DISTILLATION REBOILERS

FILENAME	DATE		DRAWN BY
EERC_P&IDS_REV0.VSD	04/12/2019		BRAD PIGGOTT

CLIENT/SITE	JOB NUMBER
EERC / RTE ETHANOL RICHARDTON, ND	50168.04
DRAWING NUMBER	SCALE
PID-10010	NONE



PRELIMINARY – NOT FOR CONSTRUCTION

FILENAME	DATE		DRAWN BY
EERC_P&IDS_REV0.VSD	04/12/2019		BRAD PIGGOTT

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REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
0	04/12/2019	ISSUED FOR REVIEW	BDP			

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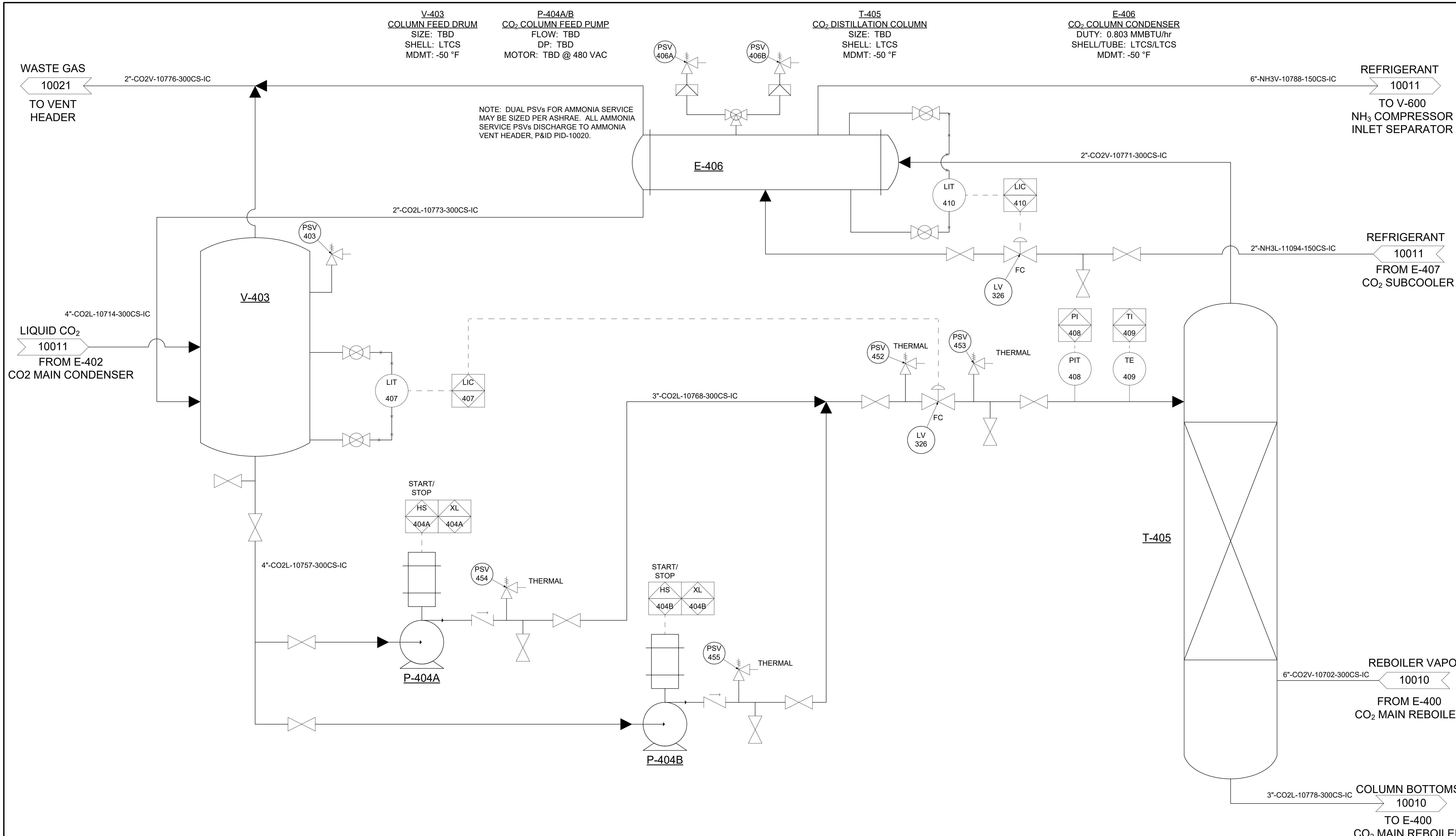
EERC – RTE CO_2 INJECTION FACILITY
CO_2 CONDENSER AND SUBCOOLER

CLIENT/SITE	JOB NUMBER
EERC / RTE ETHANOL RICHARDTON, ND	50168.04
DRAWING NUMBER	SCALE
PID-10011	NONE



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0	04/12/2019	ISSUED FOR REVIEW	BDP			

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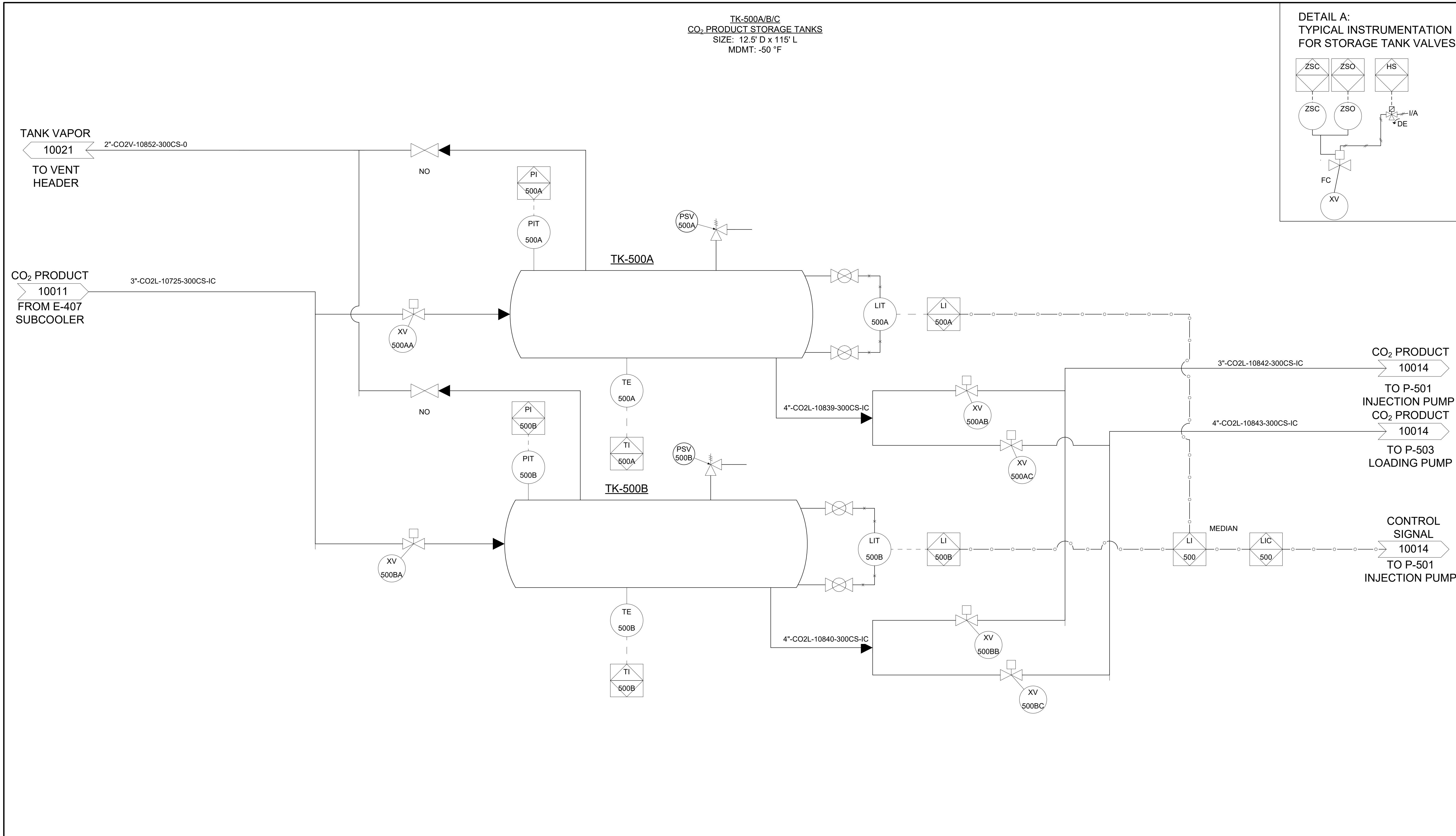
EERC – RTE CO_2 INJECTION FACILITY
CO_2 DISTILLATION

FILENAME	EERC_P&IDS_REV0.VSD
DATE	04/12/2019
DRAWN BY	BRAD PIGGOTT
CLIENT/SITE	EERC / RTE ETHANOL RICHARDTON, ND
JOB NUMBER	50168.04
DRAWING NUMBER	PID-10012
SCALE	NONE



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EERC_P&IDS_REV0.VSD	04/12/2019		BRAD PIGGOTT

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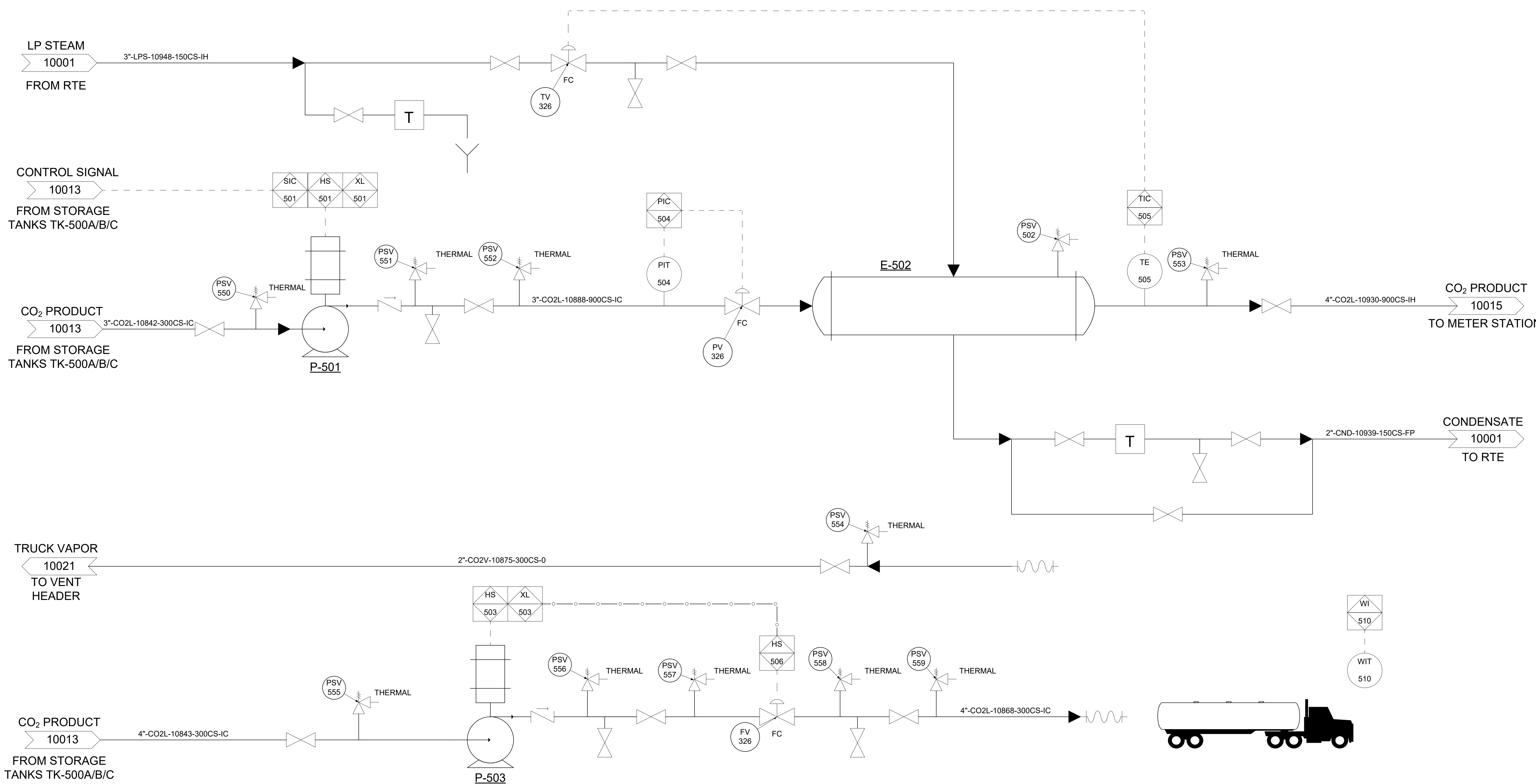
EERC – RTE CO_2 INJECTION FACILITY
PRODUCT STORAGE

CLIENT/SITE	JOB NUMBER
EERC / RTE ETHANOL RICHARDTON, ND	50168.04
DRAWING NUMBER	SCALE
PID-10013	NONE

P-501
CO_2 INJECTION PUMP
FLOW: 54,055 lb/hr
DP: 1,209 psi
MOTOR: 150 hp @ 480 VAC

E-502
CO_2 PRODUCT HEATER
DUTY: 1.695 MMBTU/HR
SHELL/TUBE: CS/LTCS
MDMT: -50 °F

P-503
CO_2 LOADING PUMP
FLOW: TBD
DP: TBD
MOTOR: TBD @ 480 VAC



PRELIMINARY – NOT FOR CONSTRUCTION

FILENAME	DATE		DRAWN BY
EERC_P&IDS_REV0.VSD	04/12/2019		BRAD PIGGOTT

REVISIONS

REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
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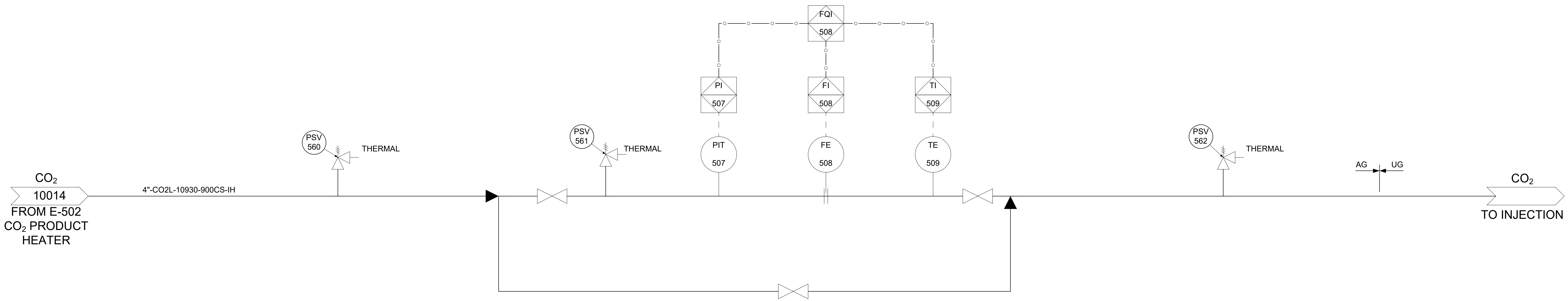
Buda, Texas 78610

EERC – RTE CO_2 INJECTION FACILITY
PRODUCT PUMPING

CLIENT/SITE	JOB NUMBER
EERC / RTE ETHANOL RICHARDTON, ND	50168.04
DRAWING NUMBER	SCALE
PID-10014	NONE



PRELIMINARY – NOT FOR CONSTRUCTION

FILENAME	DATE		DRAWN BY
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REVISIONS

REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
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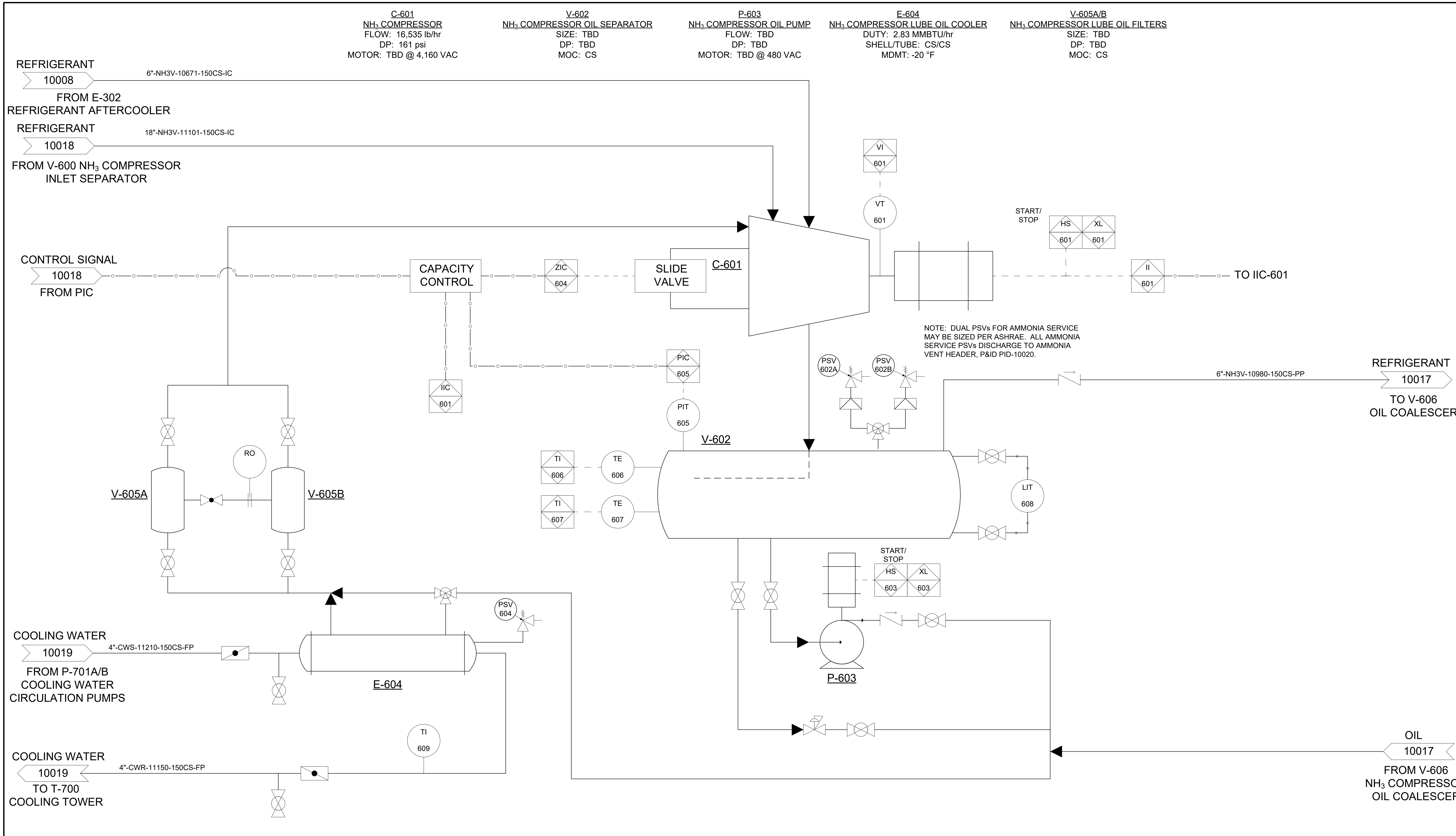
EERC – RTE CO_2 INJECTION FACILITY
INJECTION METER STATION

CLIENT/SITE	JOB NUMBER
EERC / RTE ETHANOL RICHARDTON, ND	50168.04
DRAWING NUMBER	SCALE
PID-10015	NONE



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0	04/17/2019	ISSUED FOR REVIEW	BDP			

FILENAME	DATE		DRAWN BY
EERC_P&IDS_REV0.VSD	04/17/2019		BRAD PIGGOTT

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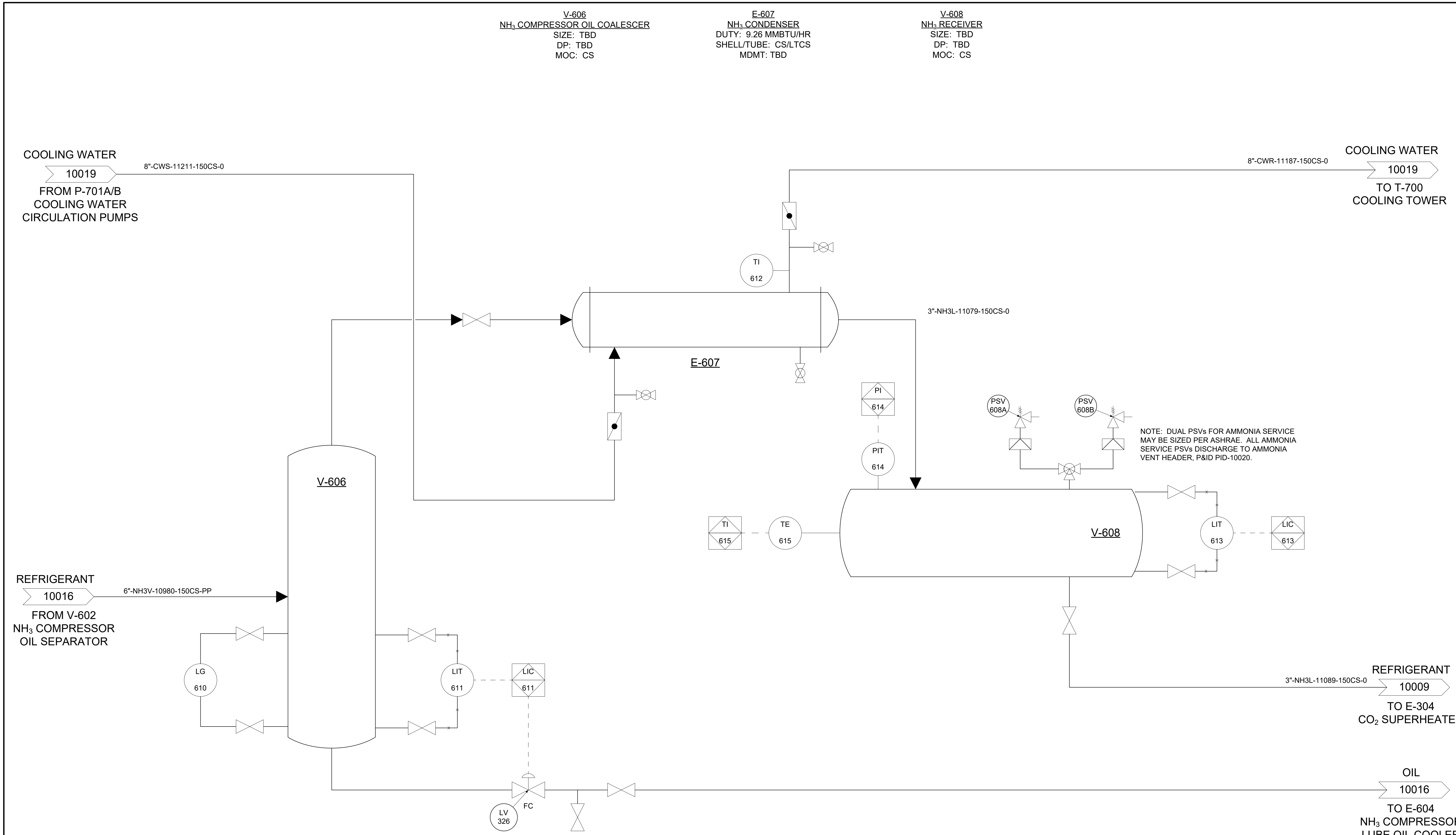
EERC – RTE CO_2 INJECTION FACILITY
REFRIGERATION COMPRESSOR

CLIENT/SITE	JOB NUMBER
EERC / RTE ETHANOL RICHARDTON, ND	50168.04
DRAWING NUMBER	SCALE
PID-10016	NONE



PRELIMINARY – NOT FOR CONSTRUCTION

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REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
0	04/17/2019	ISSUED FOR REVIEW	BDP			

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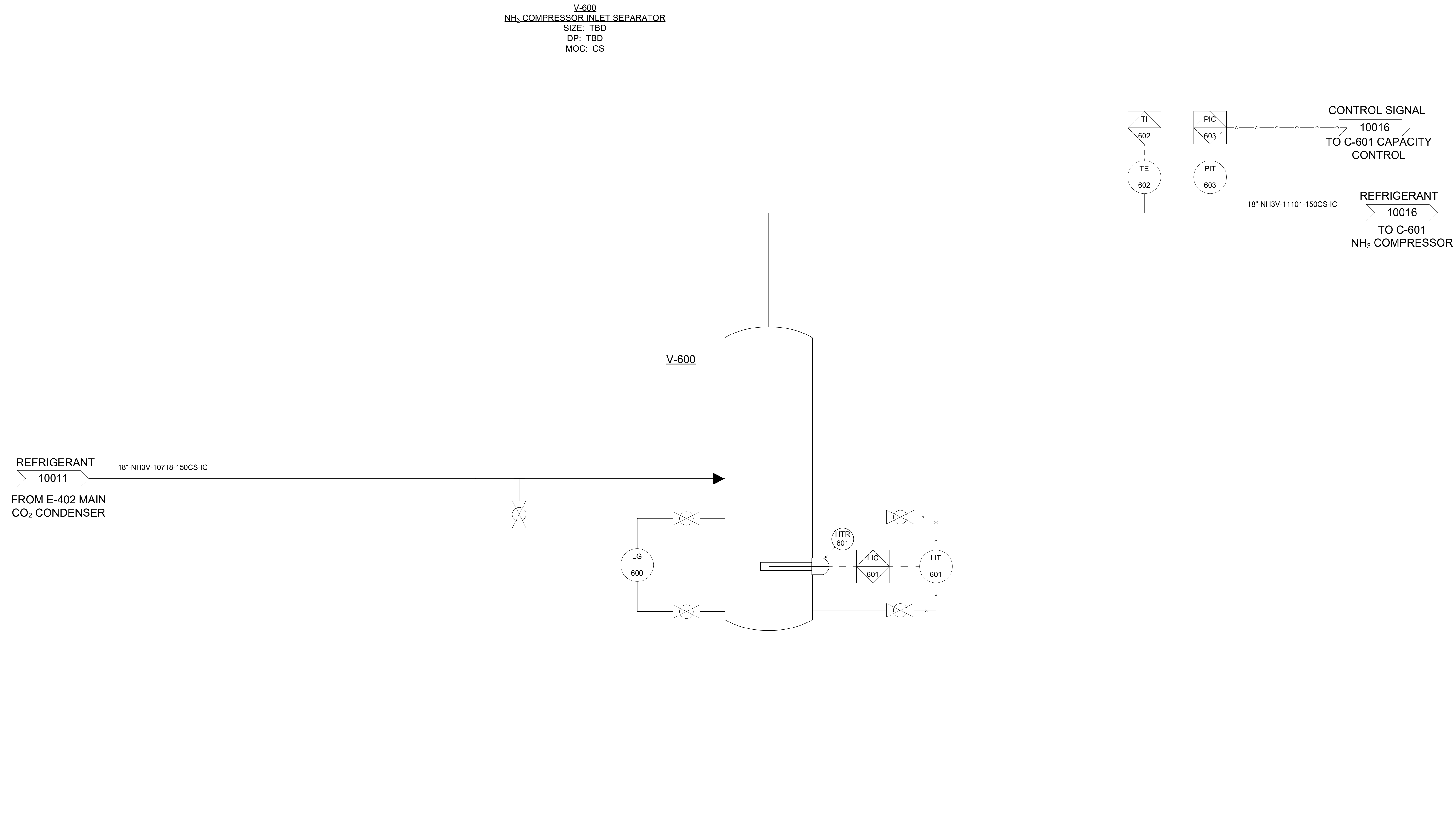
Buda, Texas 78610

EERC – RTE CO_2 INJECTION FACILITY
NH_3 CONDENSER AND RECEIVER

CLIENT/SITE	JOB NUMBER
EERC / RTE ETHANOL RICHARDTON, ND	50168.04
DRAWING NUMBER	SCALE
PID-10017	NONE



PRELIMINARY – NOT FOR CONSTRUCTION

FILENAME	DATE		DRAWN BY
EERC_P&IDS_REV0.VSD	04/12/2019		BRAD PIGGOTT

REVISIONS

REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
0	04/12/2019	ISSUED FOR REVIEW	BDP			

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Buda, Texas 78610

EERC – RTE CO_2 INJECTION FACILITY
NH_3 COMPRESSOR INLET SEPARATION

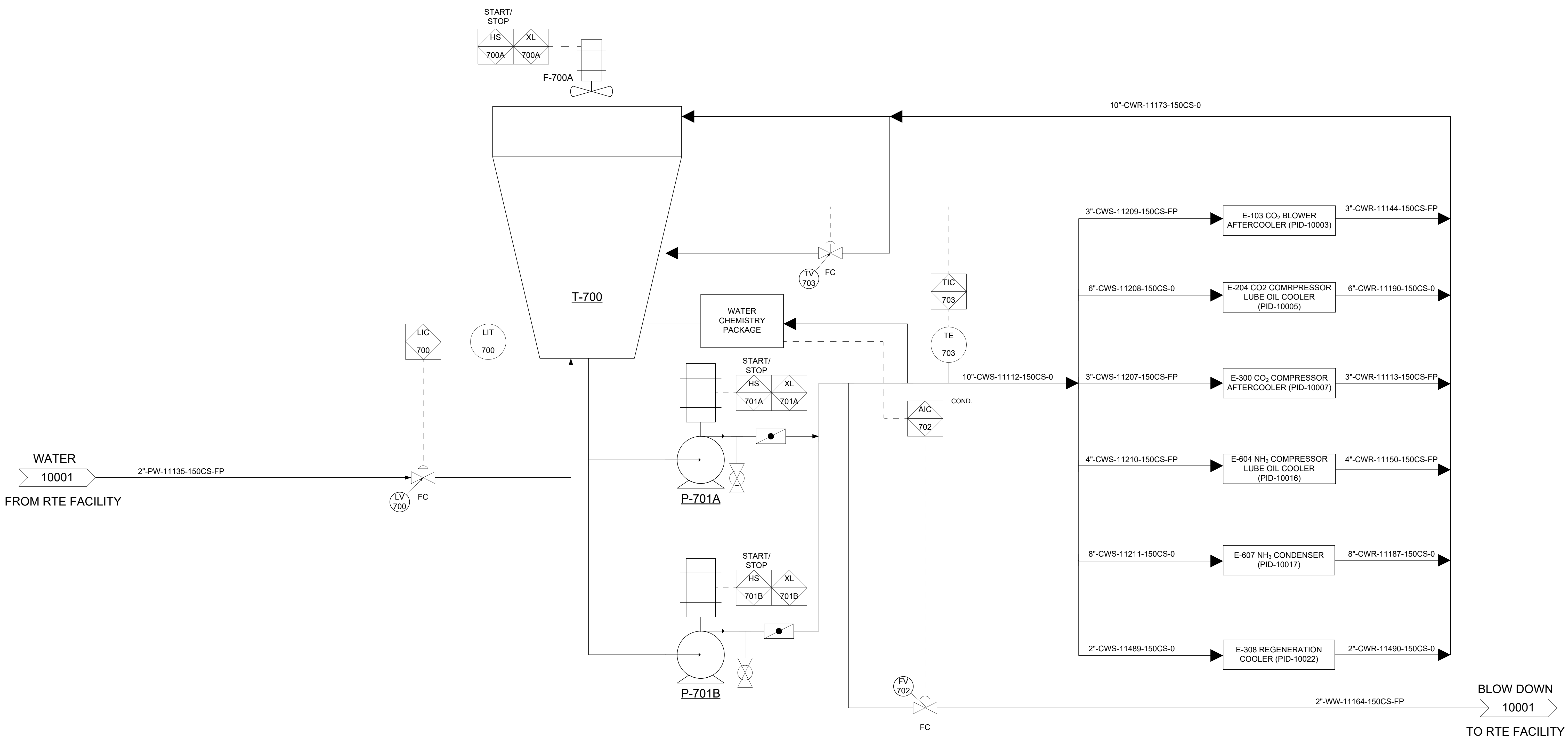
CLIENT/SITE	JOB NUMBER
EERC / RTE ETHANOL RICHARDTON, ND	50168.04
DRAWING NUMBER: 10018	SCALE: NONE

T-700
COOLING TOWER
SIZE: 21.1 MMBTU/HR
CELLS: 2

F-700A
COOLING TOWER FAN
FLOW: TBD
DP: TBD
MOTOR: TBD @ 480 VAC

P-701A/B
COOLING WATER CIRCULATION PUMPS
FLOW: 1,695 gpm
DP: 50 psi
MOTOR: 66 hp @ 480 VAC

NOTES
1. ORDER OF EXCHANGERS TO BE DETERMINED DURING DETAILED DESIGN.
2. SEE INDIVIDUAL P&IDs FOR BALANCING VALVES AND TEMPERATURE GAUGES.



PRELIMINARY – NOT FOR CONSTRUCTION

FILENAME	DATE		DRAWN BY
EERC_P&IDS_REV0.VSD	04/12/2019		BRAD PIGGOTT

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REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
0	04/12/2019	ISSUED FOR REVIEW	BDP			

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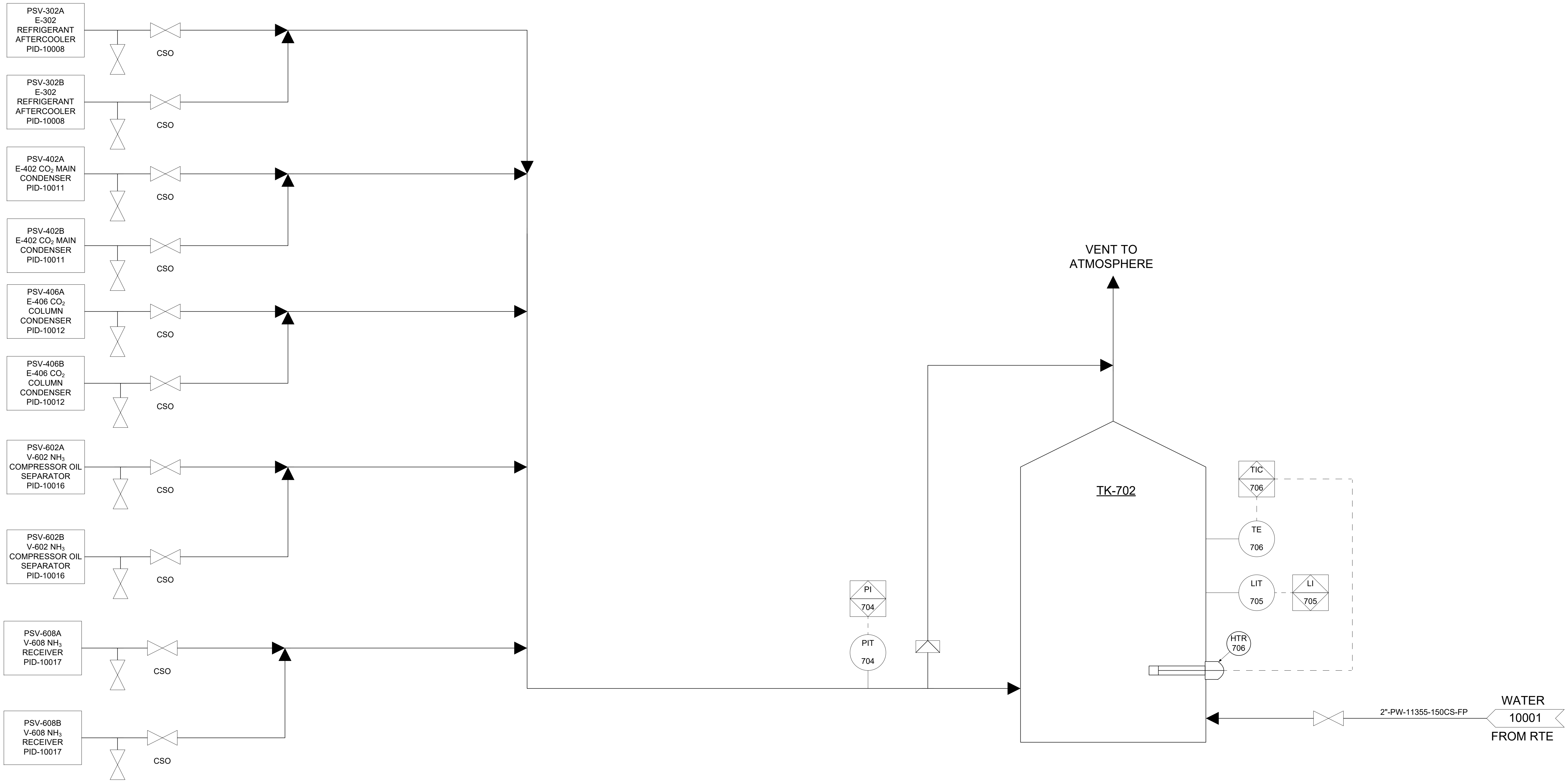
Buda, Texas 78610

EERC – RTE CO_2 INJECTION FACILITY
COOLING TOWER

CLIENT/SITE	JOB NUMBER
EERC / RTE ETHANOL RICHARDTON, ND	50168.04
DRAWING NUMBER	SCALE
PID-10019	NONE

TK-702
NH3 VENT HEADER TANK
SIZE: TBD
DP: TBD
MOC: CS

PIPING NOTES
1. PIPING TO SLOPE CONTINUOUSLY DOWNSTREAM 1" EVERY 10'.
2. TRIMERIC RECOMMENDS NO POCKETS IN VENT HEADER PIPING.
3. TRIMERIC RECOMMENDS THAT CONNECTIONS TO MAIN HEADER ALLOWED FROM THE TOP ONLY AT 45°.



PRELIMINARY – NOT FOR CONSTRUCTION

FILENAME	DATE		DRAWN BY
EERC_P&IDS_REV0.VSD	04/18/2019		BRAD PIGGOTT

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REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
0	04/18/2019	FOR REVIEW	BDP			

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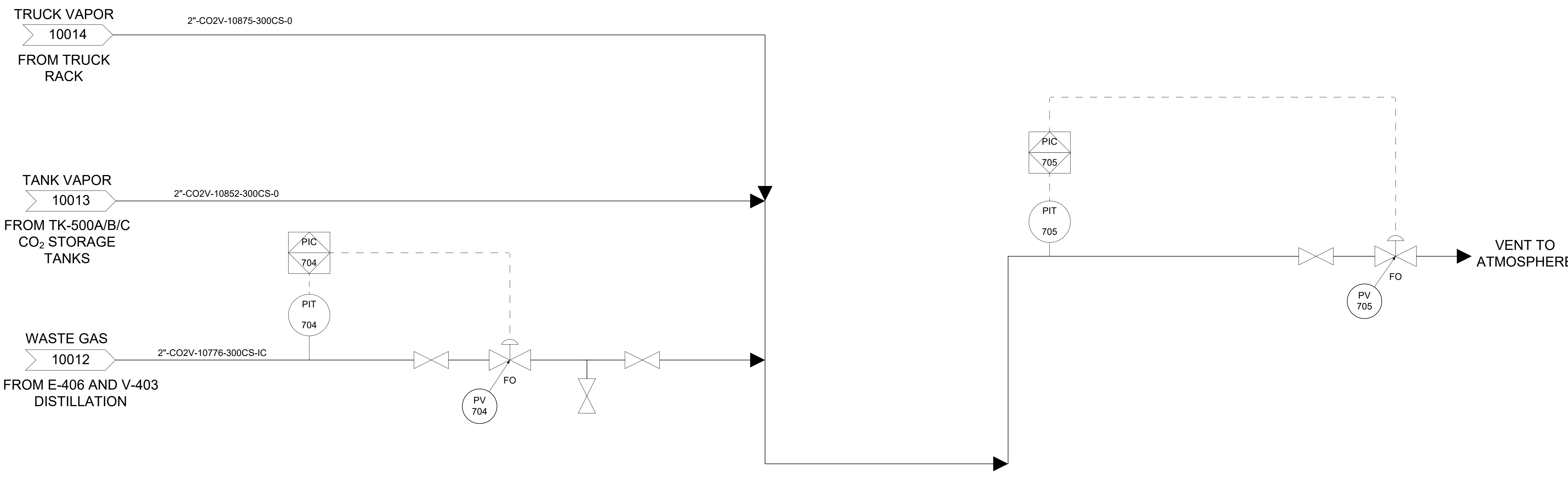
Buda, Texas 78610

EERC – RTE CO_2 INJECTION FACILITY
AMMONIA RELIEF HEADER

CLIENT/SITE	JOB NUMBER
EERC / RTE ETHANOL RICHARDTON, ND	50168.04
DRAWING NUMBER	SCALE
PID-10020	NONE



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EERC_P&IDS_REV0.VSD	04/18/2019		BRAD PIGGOTT

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REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
0	04/18/2019	FOR REVIEW	BDP			

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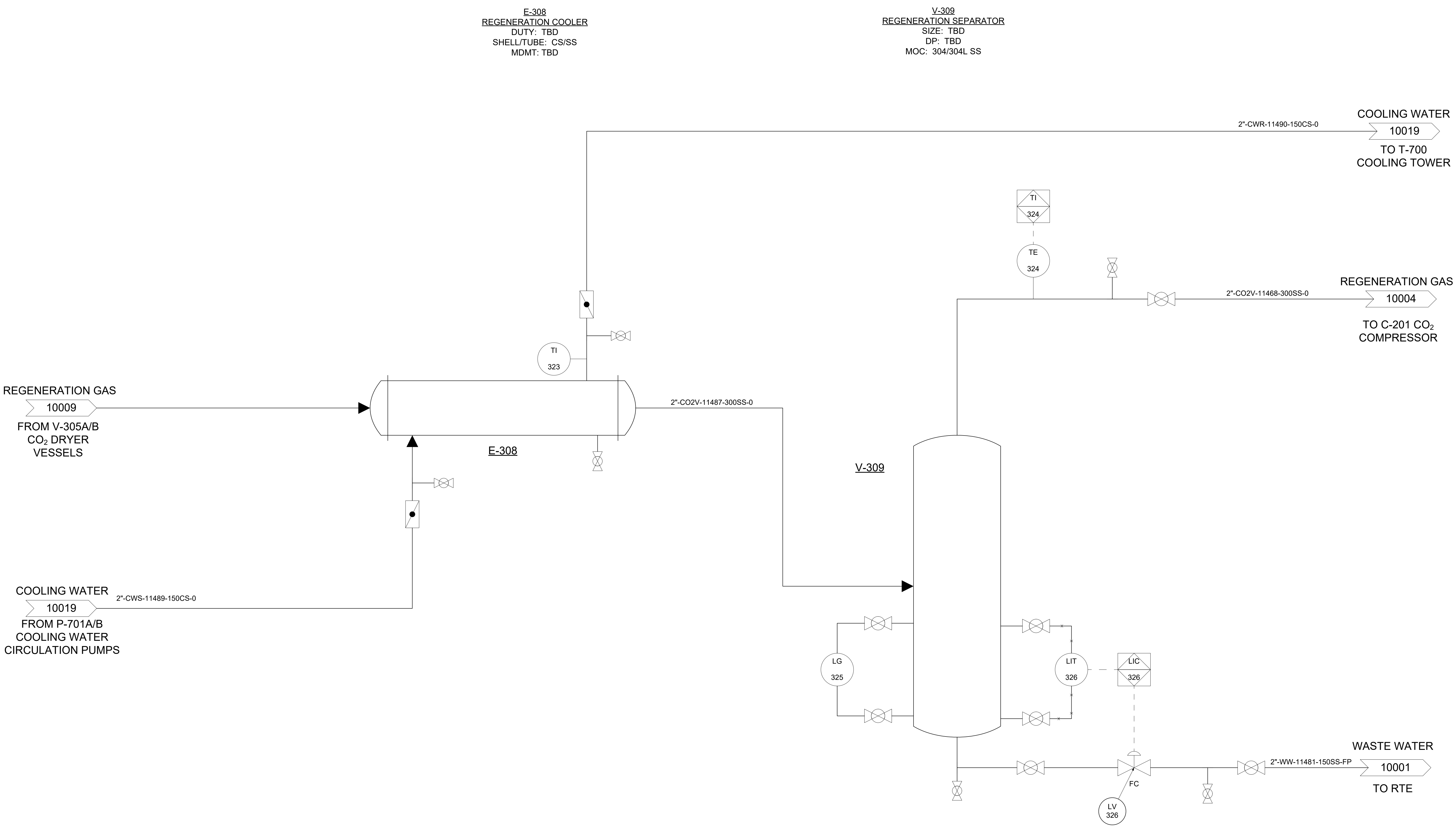
Buda, Texas 78610

EERC – RTE CO_2 INJECTION FACILITY
WASTE GAS VENT HEADER

CLIENT/SITE	JOB NUMBER
EERC / RTE ETHANOL RICHARDTON, ND	50168.04
DRAWING NUMBER	SCALE
PID-10021	NONE



PRELIMINARY – NOT FOR CONSTRUCTION

FILENAME	DATE		DRAWN BY
EERC_P&IDS_REV0.VSD	04/15/2019		BRAD PIGGOTT

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REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
0	04/15/2019	ISSUED FOR REVIEW	BDP			

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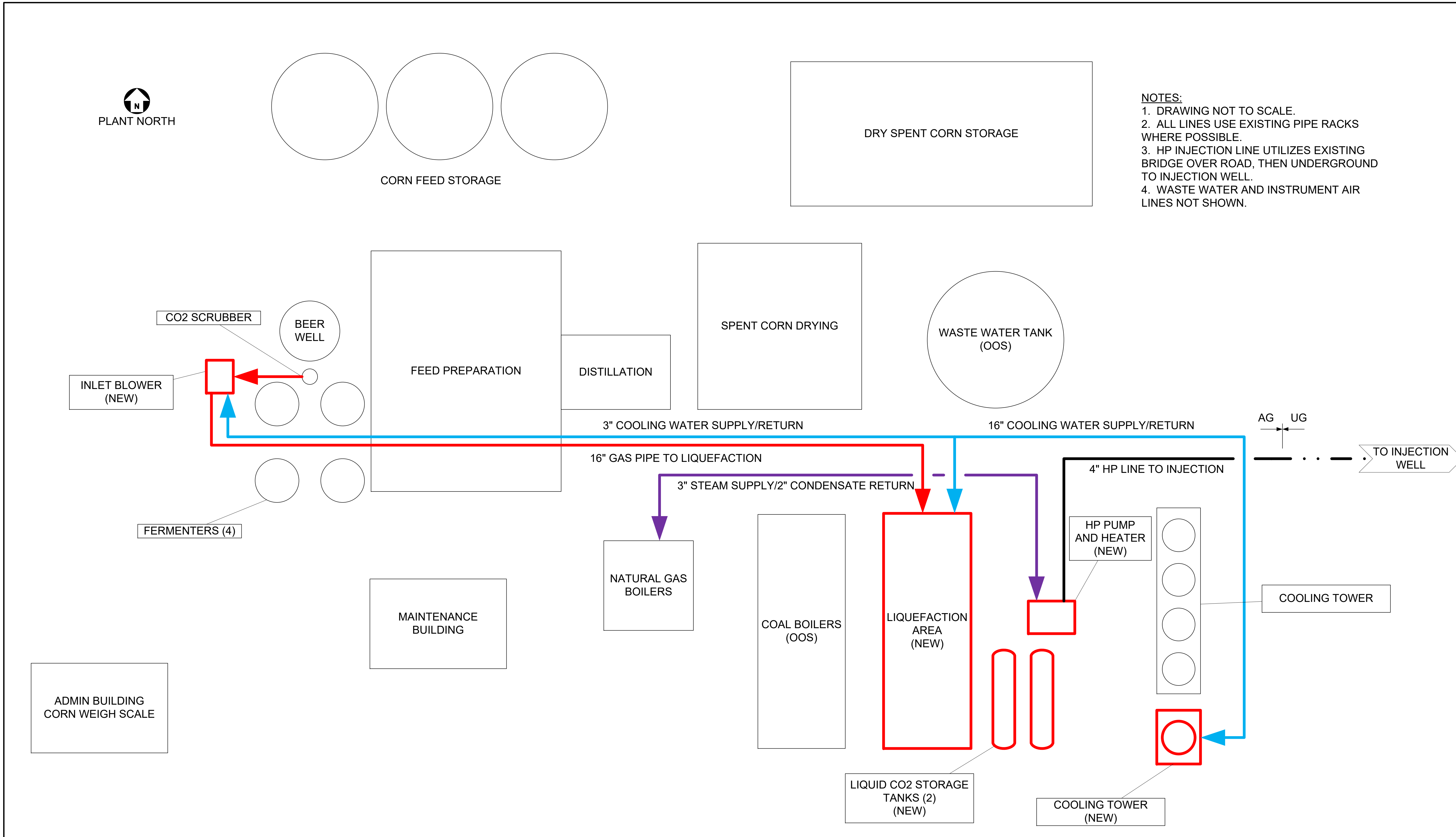
Buda, Texas 78610

EERC – RTE CO_2 INJECTION FACILITY
REGENERATION GAS COOLING

CLIENT/SITE	JOB NUMBER
EERC / RTE ETHANOL RICHARDTON, ND	50168.04
DRAWING NUMBER	SCALE
PID-10022	NONE

APPENDIX C

PRELIMINARY PLOT PLAN



NOTES:
1. DRAWING NOT TO SCALE.
2. ALL LINES USE EXISTING PIPE RACKS WHERE POSSIBLE.
3. HP INJECTION LINE UTILIZES EXISTING BRIDGE OVER ROAD, THEN UNDERGROUND TO INJECTION WELL.
4. WASTE WATER AND INSTRUMENT AIR LINES NOT SHOWN.

CONFIDENTIAL

PRELIMINARY – NOT FOR CONSTRUCTION

FILENAME: EERC_RTE CAPTURE FACILITY PLOT PLAN_0.VSD
DATE: 05/08/2019
DRAWN BY: BRAD PIGGOTT

REVISIONS

REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
0	05/08/2019	FOR REVIEW MEETING	BDP	AEV		

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Buda, Texas 78610

EERC – RTE CO2 INJECTION FACILITY
PRELIMINARY PLOT PLAN

CLIENT/SITE: EERC/RTE ETHANOL RICHARDTON, ND
JOB NUMBER: 50168.04
DRAWING NUMBER: PLT-10000
SCALE: NONE

APPENDIX B

BASELINE NEAR-SURFACE SAMPLING PROGRAM

BASELINE NEAR-SURFACE SAMPLING PROGRAM

INTRODUCTION

The Energy & Environmental Research Center (EERC) conducted near-surface (characterization) sampling in the vicinity of the Red Trail Energy (RTE) ethanol facility in Richardton, North Dakota. The primary objective of this sampling program was to establish concentrations and seasonal variations in groundwater and soil gas chemistries. This was accomplished by collecting groundwater and soil gas samples located in and around RTE property. Detailed analyses (both field and laboratory) were conducted on all samples. To capture seasonal variations in both environments, sampling events occurred in May (spring), August (summer), and November (fall) 2019.

Near-Surface Sampling Program

Near-surface sampling discussed herein comprises 1) sampling of shallow groundwater aquifers (<2000-feet depth in the study area) and 2) sampling of soil gas in the shallow vadose zone (<15-feet depth). Sampling and chemical analysis of these zones provide reference concentrations of chemical constituents, including carbon dioxide (CO_2), which can be used as part of a comprehensive subsurface-to-surface carbon capture and storage (CCS) monitoring program. Long-term monitoring programs are conducted to comply with permitting requirements, provide a defensible source of data to show that near-surface environments are not adversely impacted by CO_2 injection, and/or provide timely identification of anomalies that could be indicative of an out-of-zone migration event should they occur.

Groundwater Sampling

Three private domestic wells with depths ranging 435–1800 feet were chosen for the RTE baseline groundwater-sampling campaign. Groundwater wells were identified using publicly available data registered with the North Dakota State Water Commission (2019) geographic information system (GIS). Of the 26 wells within the RTE CCS study area, many were relatively shallow (<300 feet) and the rest were found to be no longer operational (i.e., from direct communication with well owners). Most residents of Richardton obtain drinking water from the Southwest Water Authority pipeline, which sources water from Lake Sakakawea in southwestern North Dakota.

Water-Sampling Protocol

Water quality parameters were measured in the field and in the laboratory. Field measurements of pH, temperature, dissolved oxygen (DO), specific conductance (SpC), and calculated total dissolved solids (TDS) were made using a YSI Professional Plus handheld multiparameter meter (Figure B-1). The YSI meter was calibrated daily. Field measurements of dissolved CO_2, alkalinity as $CaCO_3$, and chloride were also measured using colorimetric titration techniques with a Hanna field test kit (Figure B-2). Water samples were also collected in the field, preserved for chosen

EERC BB43848.CDR

Figure B-1. YSI Professional Plus handheld multiparameter meter used for field measurement of water quality parameters.

EERC BB44146.CDR

Figure B-2. Hanna field test kit for alkalinity as $CaCO_3$, dissolved CO_2, and chloride measurements.

analyses and submitted to the respective laboratories for detailed physical and chemical characterization.

Field Analyses

The YSI handheld multiparameter meter was calibrated daily prior to sampling in accordance with the manufacturer-specified procedures. The YSI probe was contacted directly to the water sample to obtain a field reading from the multiparameter meter. TDS measurements were calculated automatically by the YSI meter, multiplying the SpC measurements by a factor of 0.65 and thus generating a direct correlation between TDS and SpC for each measurement. All results were recorded on a data sheet.

Groundwater samples were collected directly from a spigot or valve using the well's submersible pump. Individual wells were purged (at a minimum) three casing volumes (typically 20 to 30 minutes of pumping) prior to sampling. Physical parameters were measured using the YSI flow-through cell (Figure B-3). Groundwater flow was connected from the well to the bottom port of the flow cell and flowed through the outflow port. The YSI handheld multiparameter meter was then turned on and monitored for DO readings to stabilize (±10%). Once the DO had stabilized, readings were recorded for the rest of the field parameters. A groundwater sample was then collected in a clean container for use in the analyses of alkalinity, dissolved CO_2, and chloride using the Hanna test kit.

Figure B-3. YSI meter set up with flow cell application for measuring groundwater sample parameters.

Samples for Laboratory Analyses

For laboratory analyses, sample bottles were collected directly from the designated groundwater well and filled carefully by EERC personnel wearing disposable gloves (to avoid potential contamination of the sample). Each sample container was labeled with a sample identification number, date, and time of sample collection. Filtration and preservation requirements for the specific laboratory analytical methods and procedures were strictly followed. Sample bottles were placed in a cooler with ice along with a completed chain-of-custody form and submitted to the appropriate laboratory for analysis.

Water Laboratory Analyses

Two laboratories were used to analyze water samples for near-surface monitoring: 1) the EERC laboratory analyzed samples for anions, cations, metals (dissolved and total), and nonmetals (Tables B-1 and B-2) and 2) Isotech Laboratories analyzed for isotopic signatures (Table B-3).

Table B-1. Laboratory Measurements for Groundwater Samples

Parameter	Method
Alkalinity	SM[1] 2320B
Bromide	EPA[2] 300.0
Chloride	EPA 300.0
Dissolved Inorganic Carbon (DIC)	EPA 9060
Dissolved Mercury	EPA 245.2
Dissolved Metals[3] (31 metals)	EPA 200.7/200.8
Dissolved Organic Carbon (DOC)	SM 5310B
Fluoride	EPA 300.0
Sulfate	EPA 300.0
Sulfide	SM 4500-S^{2-} F
TDS	SM 2540C
Total Inorganic Carbon (TIC)	EPA 9060
Total Mercury	EPA 7470A
Total Metals[2] (31 metals)	EPA 6010B/6020
Total Organic Carbon (TOC)	SM 5310B

[1] Standard method; American Public Health Association (2017).
[2] U.S. Environmental Protection Agency.
[3] See Table B-2 for entire sampling list of total and dissolved metals.

Table B-2. Total and Dissolved Metals and Cation Measurements for Groundwater Samples

Metals	Major Cations	Trace Metals
Antimony	Barium	Aluminum
Arsenic	Boron	Bismuth
Beryllium	Calcium	Cobalt
Cadmium	Iron	Lithium
Chromium	Magnesium	Molybdenum
Copper	Manganese	Thorium
Lead	Phosphorus	Uranium
Mercury	Potassium	Vanadium
Nickel	Silicon	
Selenium	Sodium	
Silver	Strontium	
Thallium		
Zinc		

Table B-3. Isotope Measurements for Groundwater Samples

Isotope	Units
δ^2H H_2O	‰[1]
$\delta^{18}O$ H_2O	‰
Tritium	TU[2]
$\delta^{13}C$ DIC	‰
^{14}C DIC	pMC[3]

[1] One tenth of a percent (0.1%).
[2] Tritium unit.
[3] Percent modern carbon.

Quality Assurance/Quality Control (QA/QC)

A field QA/QC program including control samples was employed to evaluate the accuracy of the sample program (field sampling and laboratory analysis). Field blanks, trip and equipment blanks, duplicate samples, and field control samples were used as part of the comprehensive QA/QC program to assure accuracy of sampling protocols. All field instruments were calibrated daily to ensure that they were operating within specifications.

Field blanks were utilized to identify sample contamination caused by exposure to ambient air during the sampling process. Field blanks consist of filling sample containers with deionized water during each sampling event. A sampling frequency of one field blank per day was employed throughout the preinjection sampling program.

Trip blanks were employed to help identify whether sample contamination specific to volatile organic carbon (VOC) analysis was present. The trip blank containers were filled with laboratory-purified water, transported and handled like a sample during field activities, then returned to the laboratory for analysis. Containers testing positive for VOCs are indicative of field contamination. One trip blank accompanied any cooler containing VOC samples.

The purpose of equipment blanks was to verify sources of contaminants were present. Equipment blanks were collected by pouring deionized water through any sampling device utilized. One equipment blank was collected from each applicable piece of equipment (flow-through cell, etc.) during each sampling event.

Duplicate samples assessed the combined accuracy of the field sampling and laboratory analysis methods. These duplicate samples were collected at the same time and location for all groundwater wells.

In order to avoid cross-contamination, disposable (nitrile) gloves were worn at all times and all field sampling equipment was decontaminated prior to use and between samples. Decontamination procedures included washing and rinsing sample probes and field multiparameter meters using Alconox® and deionized water.

Water Analysis Results

Baseline sampling and analysis were conducted in May, August, and November 2019. A total of three locations were selected for water sample collection and analysis to assess baseline water quality, identifying naturally occurring concentration levels and seasonal variations in water chemistries near the RTE CCS project site. These locations included three private domestic wells ranging 435–1800 feet. A combination of field analytical measurements and laboratory analyses was used. The following is a discussion of water analysis results.

Field Baseline Analytical Results

Field analyses included pH, temperature, DO, SpC, dissolved CO_2, and alkalinity ($CaCO_3$). Groundwater samples were fairly consistent, showing some seasonal variation (Table B-4). All groundwater samples were alkaline, with a pH range of 8.2 to 8.5 and an average pH of around 8.3 at the time of sampling. Groundwater temperatures were variable, ranging from 3° to 13°C (37° to 55°F), but no exceptional values were noted for the sampling conditions. DO levels in the groundwater were relatively low (<5 mg/L). The range of SpC was 1850–2740 μS/cm, with an average of 2200 μS/cm. Alkalinity as $CaCO_3$ was >950 mg/L in all samples. In addition, dissolved CO_2 was measured for each groundwater sample collection, with all results indicating levels below the detectable limit of 1 mg/L.

Table B-4. Results of Groundwater Field Readings

Field Parameters	May		August		November	
	Range	***Avg***	***Range***	***Avg***	***Range***	***Avg***
pH (pH unit)	8.18–8.21	8.20	8.36–8.46	8.41	8.24–8.51	8.41
Temperature, °C	3.03–8.55	5.79	11.4–12.7	12.0	8.9–11.0	9.87
SpC, μS/cm	1850–2640	2250	1890–2740	2190	1890–2730	2180
DO, mg/L	3.13–4.9	4.02	2.3–3.6	3.0	0.17–0.66	0.37
TDS (calculated), mg/L	1200–1720	1460	1160–1720	1360	1230–1780	1420
Chloride, mg/L	10–20	15	10–22	17.3	8–28	15.3
Alkalinity as $CaCO_3$, mg/L	1070–1570	1320	1010–1540	1203	960–1540	1250

Laboratory Baseline Analytical Results

Inorganic Analyses

Water quality parameters were selected to understand the natural seasonal changes in groundwater within the RTE CCS study region. Table B-5 provides average concentrations of ionic constituents for the three sampling events alongside drinking water recommendations known as maximum contaminant levels (MCLs) set by EPA. Anion concentrations were dominated by bicarbonate, averaging ~1450 mg/L, followed by carbonate, sulfate, and chloride. Cation concentrations consisted largely of sodium, averaging ~580 mg/L, and to a lesser extent, calcium and magnesium (<25 mg/L). All parameters regulated by EPA were below EPA's primary and secondary drinking water standards, with the exception of fluoride and TDS. While average fluoride concentrations were below 4 mg/L, individual wells exceeded the EPA MCL value. All wells contained TDS >1000 mg/L, above the EPA-recommended secondary drinking water standard of 500 mg/L. Therefore, human consumption of the well waters is not recommended without testing by a state-certified laboratory.

Table B-6 provides the laboratory analyses for metals and trace metals conducted on groundwater samples. Almost all of the samples had nondetectable concentrations, and those that were detected (arsenic, copper, and zinc) were below EPA MCL values. Although the laboratory analysis detected mercury in one sample collected during the November sampling event, mercury was also detected in the equipment blank, meaning contamination during the sampling process likely occurred. Again, human consumption of the well waters is not recommended without further testing.

Table B-5. Results of Groundwater Laboratory Analyses

Parameter, mg/L	**May** *Range*	*Avg*	**August** *Range*	*Avg*	**November** *Range*	*Avg*	***EPA MCLs***
				Anions			
Bicarbonate	1250–1920	1585	1210–1820	1423.3	1170–1760	1380	*NR*[1]
Bromide	<1	<1	<1	<1	<1	<1	*NR*
Carbonate	0–27.1	13.6	13.6–21.3	18.1	1.40–45.3	22.4	*NR*
Chloride	8.50–18.8	13.7	9.82–21.4	17.1	7.50–16.1	15.9	*250*[2]
Fluoride[1]	<1–5.60	3.05	<1–4.80	3.22	1.10–5.50	3.6	*4.0*[3]
Sulfate	7.60–27.5	17.6	8.80–28.9	20.6	8.18–41.5	25.8	*250*[2]
Sulfide[1]	<0.05	<0.05	<0.05	<0.05	<0.05–0.044	0.112	*NR*
				Cations			
Barium	0.083–0.104	0.094	0.139–0.172	0.160	0.0838–0.147	0.114	*2*[3]
Boron	0.937–1.75	1.34	0.632–1.305	0.873	0.680–1.48	0.98	*NR*
Calcium	1.94–2.91	2.43	2.11–22.4	9.20	2.05–25.3	10.1	*NR*
Iron	0.02–0.38	0.2	0.015–0.413	0.155	0.038–0.667	0.257	*0.3*[2]
Magnesium	1.00–1.38	1.19	1.17–14.3	5.66	1.05–17.9	6.77	*NR*
Manganese[4]	<0.005	<0.005	<0.005–0.022	0.001	<0.005–0.0132	0.007	*NR*
Phosphorus	0.146–0.362	0.362	0.151–0.422	0.302	0.160–0.400	0.310	*NR*
Potassium	2.30–2.50	2.40	2.18–11.6	5.41	2.35–12.1	5.65	*NR*
Silicon	3.42–5.03	4.23	3.64–5.05	4.12	3.49–4.93	4.06	*NR*
Sodium	521–763	642	457–720	558	450–745	570	*NR*
Strontium[4]	0.092–0.177	0.135	0.115–0.275	0.202	<0.1–0.252	0.162	*NR*
Measured TDS	1160–1720	1440	1140–1700	1340	1100–1700	1300	*500*[2]

[1] Not included in federal or state drinking water regulations.

[2] Regulated only by national secondary drinking water regulations, which are nonenforceable guidelines regulating contaminants that may cause cosmetic or aesthetic effects in drinking water.

[3] Regulated by EPA's national drinking water regulations, which are legally enforceable guidelines regulating the MCL allowed in drinking water.

[4] Used half of the detection limit when averaging wells.

Table B-6. Results of Groundwater Laboratory Analyses for Metals and Trace Metals

Metal, mg/L	May	August	November	*EPA MCLs*
Aluminum	<0.005	<0.005	<0.005	*0.2*[1]
Antimony	<0.005	<0.005	<0.005	*0.006*[2]
Arsenic	<0.001	<0.001–0.002	<0.001–0.002	*0.01*[2]
Beryllium	<0.004	<0.004	<0.004	*0.004*[2]
Bismuth	<0.0005	<0.0005	<0.0005	*NR*[3]
Cadmium	<0.002	<0.002	<0.002	*0.005*[2]
Chromium	<0.005	<0.005	<0.005	*0.1*[2]
Cobalt	<0.005	<0.005	<0.005	*NR*
Copper	<0.005	<0.005–0.012	<0.005	*1.3*[2]
Lead	<0.005	<0.005	<0.005	*0.015*[2]
Lithium	0.053–0.096	0.04–0.068	0.075–0.138	*NR*
Mercury	<0.0001	<0.0001	<0.0001	*0.002*[2]
Molybdenum	0.009–0.013	0.009–0.02	0.008–0.0165	*NR*
Nickel	<0.005	<0.005	<0.005	*NR*
Selenium	<0.001	<0.001	<0.001	*0.05*[2]
Silver	<0.005	<0.005	<0.005	*0.10*[1]
Thallium	<0.0005	<0.0005	<0.0005	*0.002*[2]
Thorium	<0.0005	<0.0005	<0.0005	*NR*
Uranium	<0.001	<0.001–0.003	<0.001–0.003	*0.03*[2]
Vanadium	<0.005	<0.005	<0.005	*NR*
Zinc	<0.005–0.104	<0.015–0.064	<0.005–0.037	*5*[1]

1 Regulated only by national secondary drinking water regulations, which are nonenforceable guidelines regulating contaminants that may cause cosmetic or aesthetic effects in drinking water.

2 Regulated by EPA's national drinking water regulations, which are legally enforceable guidelines regulating the MCL allowed in drinking water.

3 Not included in federal or state drinking water regulations.

Water Isotopes

Isotopes were also analyzed, such as isotopic composition of water (H_2O, δ^2H, and $\delta^{18}O$) and carbon isotopic composition of DIC ($\delta^{13}C$). Table B-7 summarizes the results of the isotopic analysis of water and DIC. The results from δ^2H and $\delta^{18}O$ analyses averaged about −146±5‰ and −18.9±0.5‰, respectively. These values appear to be consistent with regional water metrics (Shaver, 1995). The results from $\delta^{13}C$ analyses averaged −7±2‰. Figure B-4 shows how this range is typical of DIC isotopes found in groundwater. Table B-7 also indicates that all three isotopes monitored may have a natural decreasing trend as environmental temperatures drop; additional monitoring is required to verify this hypothesis.

Table B-7. Isotopic Composition of Water (δ^2H and $\delta^{18}O$) and Carbon Isotopic Composition of DIC ($\delta^{13}C$) for Groundwater Samples

Sampling	δ^2H H_2O, ‰		$\delta^{18}O$ H_2O, ‰		$\delta^{13}C$ DIC, ‰	
Month	***Range***	***Avg***	***Range***	***Avg***	***Range***	***Avg***
May	−150 to −144	−147	−19.4 to −18.6	−19.0	−9.1 to −5.5	−7.3
August	−151 to −145	−147	−19.4 to −18.6	−19.0	−9.2 to −5.5	−7.0
November	−150 to −143	−145	−19.4 to −18.5	−18.8	−9.3 to −5.5	−7.1

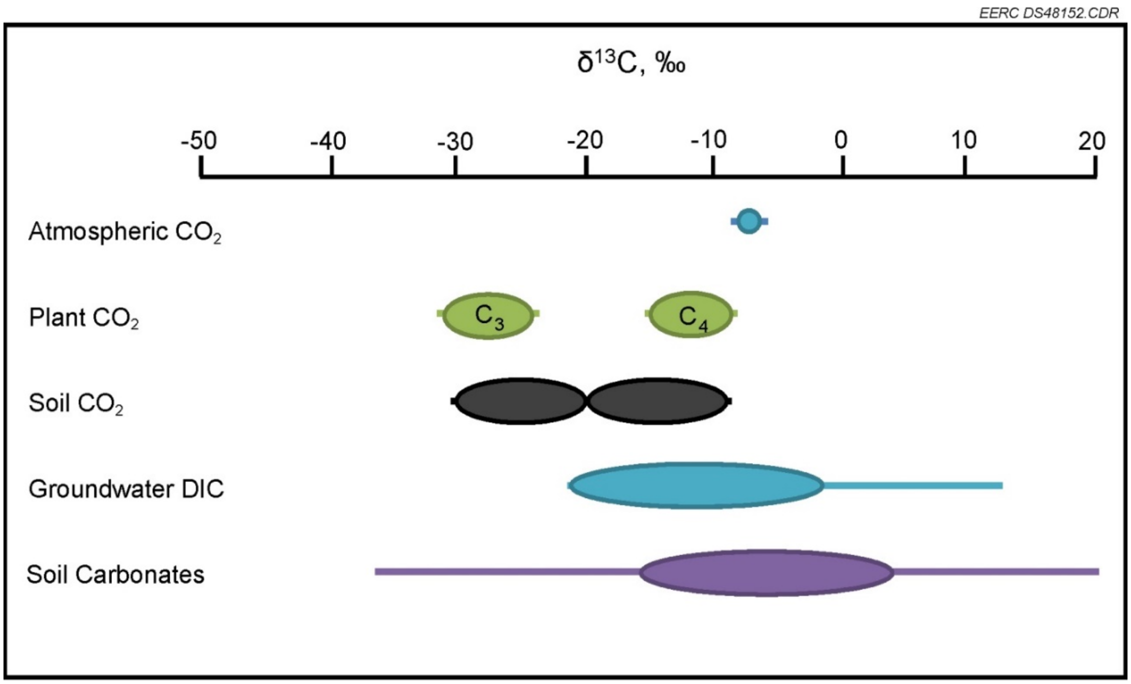

Figure B-4. Plot of the variation in ^{13}C fractionation observed in various components of the near-surface environment; plants with a C_3 metabolism make up the vast majority of plant species alive in the world today and produce isotopic signatures readily observed in soil gas samples (modified from Clark and Fritz, 1997).

Soil Gas Sampling and Analysis

Site reconnaissance activities identified potential soil gas-sampling locations within the RTE CCS study region, based on access to sample from a driveway/road. Exact sampling locations were determined on-site after a utility-locate was performed. A total of 11 soil gas-sampling sites were established, six on RTE property and five on private land. To ensure accuracy for repeat sampling, all locations were surveyed using GPS (global positioning system). Several relatively large rainfall events occurred prior to all sample events, which prevented certain locations from being sampled.

Soil Gas Survey

Vadose zone soil gas monitoring directly measures the characteristics of the soil atmosphere and is an indirect indicator of processes occurring in and below a sampling horizon. Soil gas sampling was accomplished using a mechanically driven probe. This method was chosen because of its cost-effectiveness, low-impact nature, and mobility. The objective of the soil gas survey was to establish preinjection values for several specific components naturally found in shallow subsurface soils. These components included hydrogen (H_2), oxygen (O_2), nitrogen (N_2), carbon monoxide (CO), CO_2, methane (CH_4), ethane (C_2H_6), and ethylene (C_2H_4).

Soil Gas-Sampling Protocol

All soil gas-sampling locations were identified and marked using GPS. A utility-locate was performed prior to the advancement of the soil gas probes. A stainless-steel rod with a retractable tip was driven into the ground (either with a slide hammer or electric rotary hammer) to a depth of approximately 3.5 feet. The rod was then retracted to expose an integrated mesh screen. Teflon tubing was attached to the end of the sample probe, and a vacuum chamber was used to purge the rod before the sample was collected. A minimum of three probe casing volumes were removed prior to sampling. The soil gas was first analyzed for CO_2, total VOCs, hydrogen sulfide (H_2S), and O_2 using a RAE System PGM-54 handheld multigas meter (shown in Figure B-5; calibrated daily based on manufacturer instructions). When gas flow was determined to be representative, two samples were collected at each location in a Tedlar® bag, labeled with the appropriate sample number and site information, and transported to the EERC laboratory for analysis. Gas sample compositions were analyzed using an Agilent 7890A refinery gas analyzer (RGA) gas analyzer GC (gas chromatograph). The second sample was then transferred to an IsoBag® for isotope analyses, including $\delta^{13}C$ of CO_2 and CH_4, by mass spectrometer at Isotech Laboratories, Champaign, Illinois.

EERC KL57847.AI

Figure B-5. RAE System PGM-54 handheld multigas meter.

Soil Gas-Sampling QA/QC

For QA/QC, a field blank (ambient air) was collected three times daily (morning, midday, day's end) through the sample probe prior to the insertion of the probe into the ground. If an anomaly was detected with the RAE handheld meter, decontamination procedures were repeated and a blank was collected again. If an anomaly continued, the calibration of the meter was confirmed. Additionally, results from the handheld meter and the EERC laboratory GC were compared for all sampling events as a QA/QC measure to ensure representative soil gas samples resulted in valid data.

Duplicate gas samples were collected at a rate of one for each ten (total samples) to assess the comparative accuracy of the field sampling and laboratory analysis. Sample collection procedures followed guidance outlined in ASTM International D-5314 (2006). Complete summaries of field parameters, GC measurements, and isotope measurements are provided in Tables B-8 and B-9, respectively.

Table B-8. Soil Gas Parameters Analyzed with Field and Laboratory Instruments

RAE Handheld Meter	Agilent Technologies RGA-GC 7890A
CO_2	CO_2
O_2	O_2
H_2S	N_2
Total VOCs	He
	H_2
	CH_4
	CO
	C_2H_6
	C_2H_4
	C_3H_8
	C_2H_8
	$(CH_3)_2CH\text{-}CH_3C_4H_{10}$
	$HC{\equiv}CH$
	$H_2C{=}CH\text{-}C_2H_5$
	$H_3C\text{-}CH{=}CH\text{-}CH_3$
	$(CH_3)_2C{=}CH_2$
	$H_3C\text{-}CH{=}CH\text{-}CH_3$
	$(CH_3)_2CH\text{-}CH_2\text{-}CH_3$
	C_5H_{12}
	$H_2C{=}CH\text{-}CH{=}CH_2$

Table B-9. Isotope Measurements of Soil Gas Samples

Isotope	Units
$\delta^{13}C$ of CO_2	‰
δD	‰
^{14}C in CO_2	pMC
^{14}C in CH_4	pMC

Soil Gas-Sampling Results

Soil gas samples were collected in May, August, and November 2019 to establish concentrations and measure seasonal variability. Several relatively large rainfall events occurred prior to all sample events, which prevented certain locations from being sampled. In May, samples were collected over two trips. Isotope samples were submitted to Isotech Laboratories for all locations sampled during the first event. It should be noted that CO_2 concentrations within a submitted sample must be >0.25% for an isotope analysis to be conducted.

Natural environmental seasonal variability was apparent, with higher average CO_2 values in the warmer month of August showing soil gas composition up to 7% CO_2 (Table B-10). Soil gas analytical results averaged 0.7% CO_2, 20% O_2, and 79% N_2.

Table B-10. Soil Gas-Sampling Results from RTE CCS Study Region

Sampling Month	CO_2, %		O_2, %		N_2, %	
	Range	***Avg***	***Range***	***Avg***	***Range***	***Avg***
May	0.13–0.62	0.30	20.4–21.3	20.8	78.1–79.2	78.7
August	0.31–6.86	1.30	14.7–21.1	19.9	78.5–79.2	78.8
November	0.11–0.97	0.63	16.4–21.3	19.7	78.6–82.6	79.6

Soil Gas Isotopes

A process-based approach to soil gas composition assessment was developed by Dr. Katherine Romanak, a geochemist at the University of Texas at Austin developing innovative approaches to monitoring geologic CO_2 storage sites (Romanak and others, 2012). Figures B-6 and B-7 depict this method by graphing the soil gas composition results comparing CO_2 with O_2 values and CO_2 with N_2/O_2 ratio, respectively, along with calculated biological respiration and oxidation of CH_4 lines. The lines show the trends of these common chemical reactions in near-surface soil and how they change with increased CO_2 in a natural environment. The figures show that all measured CO_2 levels were within expected environmental ratios with O_2 and N_2 and the warmer climate temperatures influencing naturally higher CO_2 levels during the visual assessment to quickly determine if further investigation is warranted (Figures B-6 and B-7, August sampling event). More information about this process-based approach is provided in the next section.

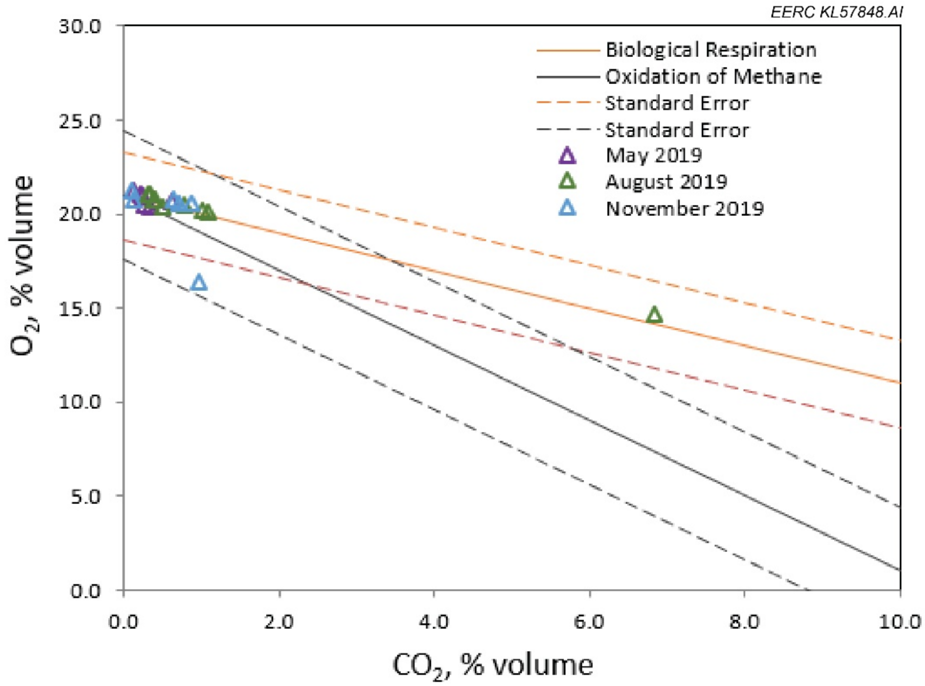

Figure B-6. Process-based evaluation using composition comparison of soil gas-sampling results from the RTE CCS study region.

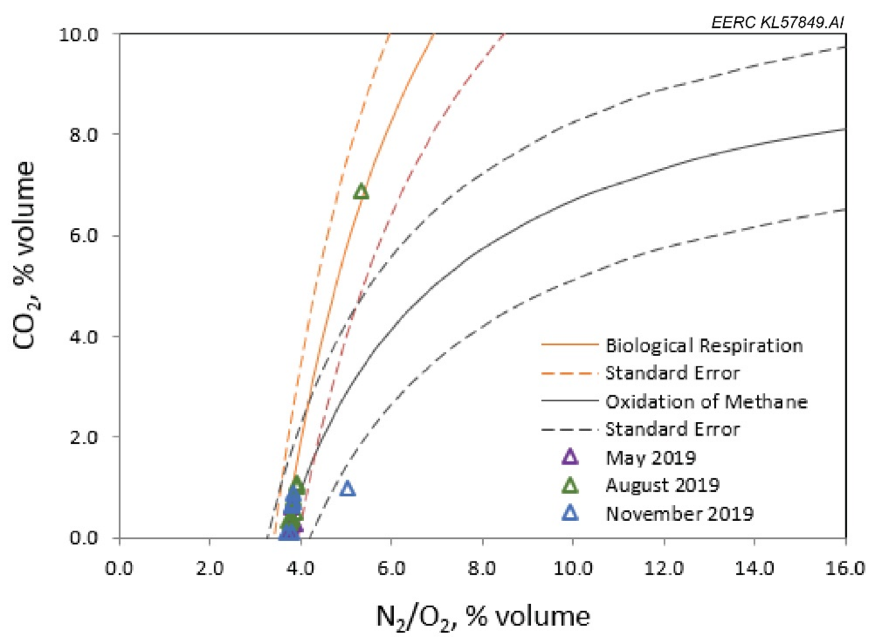

Figure B-7. Process-based evaluation using composition ratio comparison for soil gas results from the RTE CCS study region.

Table B-11 summarizes the results for the carbon isotopic composition of CO_2 (δC^{13}) in soil gas. The δC^{13} varies within 11 sampling locations, averaging −23 ± 2‰. The negative $\delta^{13}C$ values suggest that the soil gas CO_2 is sourced more frequently from C_3 plants than C_4 plants (Webb and Longstaffe, 2010); plants with a C_3 metabolism (approximately −33‰ to −23‰) make up the vast majority of plant species alive in the world today and produce isotopic signatures readily observed in soil gas samples (Figure B-4).

Table B-11. Carbon Isotopic Composition ($\delta^{13}C$, ‰) of Naturally Occurring CO_2 in Soil Gas Samples Within the RTE CCS Study Region

Sampling Month	Range	Average
May	−23.7 to −22.3	−22.9
August	−24.1 to −21.8	−22.9
November	−24.9 to −23.3	−24.3

Soil Gas Process-Based Assessment Approach

Monitoring CO_2 at the near-surface vadose zone using concentration-based techniques involves several challenges: 1) high variability of CO_2 generated in situ could mask a moderate migration signal; 2) 1 year of background characterization cannot completely account for CO_2 variability from climatic, land use, and ecosystem variations over the lifetime (e.g., decades or centuries) of a CO_2 storage study; and 3) background measurements can require long lead times, potentially hindering a project's progress (Romanak and others, 2012).

Romanak and others (2012) developed a process-based approach that provides a methodology for determining whether vadose zone CO_2 results from natural background soil respiration or potentially from out-of-zone migration from geologic gases. Figure B-8 illustrates the process-based approach.

Natural or background levels of soil gas CO_2 resulting from the aerobic microbial oxidation of organic matter are represented in simple terms by Equation 1, where 1 mole of oxygen produces 1 mole of CO_2 and plots with a slope of −1 on a graph of O_2 versus CO_2 (the red line on Figure B-8). CH_4 may be produced under anaerobic soil conditions or may be present above oil- and gas-producing zones within the soil. The oxidation of CH_4 can be another source of background CO_2 and is represented by Equation 2, where 2 moles of oxygen produce 1 mole of CO_2 and plot with a slope of −0.5 on a graph of O_2 versus CO_2 (the black line in Figure B-8).

$$CH_2O + O_2 \rightarrow CO_2 + H_2O \qquad \text{[Eq. 1]}$$

$$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O \qquad \text{[Eq. 2]}$$

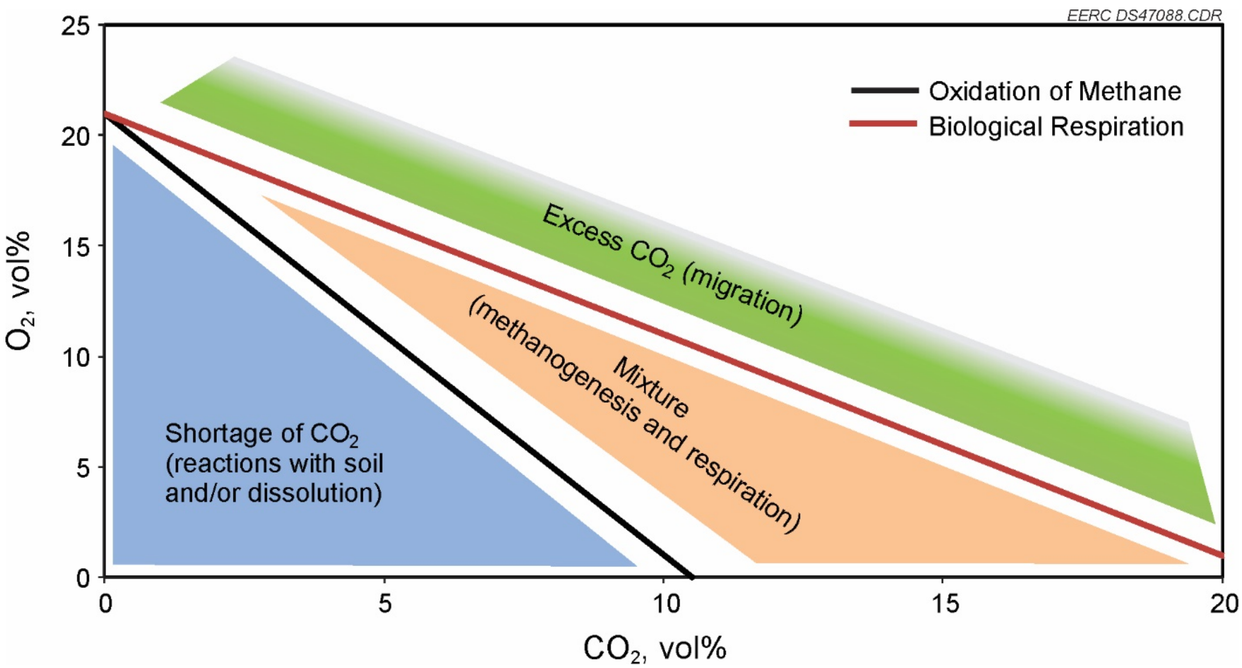

Figure B-8. Process-based analytical method for monitoring soil gas concentrations of CO_2 and O_2 (Romanak and others, 2012).

Soil gas O_2 and CO_2 data plotting above the red line (biological respiration) would be indicative of excess CO_2 or a potential vertical migration of CO_2. Those same data that plot below the black line (CH_4 oxidation) would be indicative of a shortage of CO_2 or a situation where soil gas CO_2 has reacted with the soil or has been dissolved in percolating precipitation. CO_2 and O_2 data that plot between the lines of biological respiration and CH_4 oxidation are representative of a mixture of those two processes.

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APPENDIX C

NORTH DAKOTA GEOLOGIC CO_2 STORAGE PERMITS TEMPLATE

NORTH DAKOTA GEOLOGIC CO_2 STORAGE PERMITS TEMPLATE

Integrated Carbon Capture and Storage for North Dakota Ethanol Production – Phase III
Task 3 – Deliverable D2

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NORTH DAKOTA GEOLOGIC CO_2 STORAGE PERMITS TEMPLATE

EXECUTIVE SUMMARY

Well drilling and CO_2 storage facility permits issued by the North Dakota Industrial Commission (NDIC) Department of Mineral Resources (DMR) are required to implement geologic CO_2 storage in North Dakota. The Energy & Environmental Research Center (EERC) has developed two permit templates to assist a technical permit writer in preparing 1) an application for permit to drill (APD) a stratigraphic test well and 2) a storage facility permit (SFP) application that are consistent with North Dakota Underground Injection Control (UIC) Class VI statutes and regulations. The APD template includes options for the design and permitting of a stratigraphic test well that can be transitioned for use as a UIC Class VI-compliant injection or monitoring well. To that end, this template also provides information for preparing the injection well permit that is required to convert and operate the stratigraphic test well to a CO_2 injection well, which can be filed in concert with the SFP application.

No SFPs have yet been issued in North Dakota. The permit application templates presented incorporate learnings and clarifications that have been garnered as the first projects advancing carbon capture and storage (CCS) in North Dakota work through the SFP process with the DMR. Each section provides a description of the intent of the section, references the relevant requirements in the North Dakota Century Code (NDCC) and North Dakota Administrative Code (NDAC), and provides a description of evidence or exhibits to be included within the section. The templates incorporate formatting that is both structured to present the information required in the permit application in a functional, logical, and consistent fashion and aligned with the permit review and public hearing process.

NORTH DAKOTA GEOLOGIC CO_2 STORAGE PERMIT TEMPLATES

1.0 INTRODUCTION

1.1 Overview

The Energy & Environmental Research Center (EERC), in conjunction with its government and industrial partners, is conducting feasibility and implementation studies for commercial carbon capture and storage (CCS) projects in North Dakota. Specifically, in partnership with Red Trail Energy, LLC (RTE), the North Dakota Industrial Commission (NDIC), and the U.S. Department of Energy (DOE), the EERC is investigating the commercial capture and geologic storage of carbon dioxide (CO_2) from the 64-million-gallon dry mill RTE ethanol facility, which emits an average of 180,000 metric tons of CO_2 annually.

Well drilling and CO_2 storage facility permits (SFP) are required to construct and operate a geologic CO_2 storage project in North Dakota. An application of permit to drill (APD) is required to drill a stratigraphic test well, which is used to acquire the necessary downhole data to complete a CO_2 SFP in North Dakota. The NDIC Department of Mineral Resources (DMR) Oil and Gas Division (Commission) has authority to regulate the geologic storage of CO_2 granted by the North Dakota Century Code (NDCC) (Chapter 38-22 Carbon Dioxide Underground Storage) and primacy to administer the underground injection control (UIC) Class VI Program. The North Dakota Administrative Code (NDAC) (Chapter 43-05-01 Geologic Storage of Carbon Dioxide) contains the regulations that predominantly govern CO_2 storage activities in the state of North Dakota.

The EERC and RTE engaged the Commission during the planning stages of a stratigraphic test well intended to support the development of an SFP application. As such, the stratigraphic test well is part of a critical path to achieving UIC Class VI compliance and has laid the foundation for what is likely to be the first CO_2 SFP application to be submitted in North Dakota. Several recommended practices and clarifications related to well design, geologic characterization, well testing, and the UIC Class VI requirements resulted from these permit discussions, the more significant of which are captured in call-out boxes throughout these templates. To date, approval to drill a stratigraphic test well for the first geologic storage project in North Dakota has been approved (NDIC File No. 37229).

This document provides application templates for the two permits that are required to move forward with the commercial geologic storage of CO_2 in North Dakota: the APD and the SFP. It also provides the information necessary to prepare an application to convert and operate a Class VI-compliant stratigraphic well as a CO_2 injection well, which is the final regulatory approval necessary prior to beginning the operations of the CO_2 storage facility.

Because CCS efforts are subject to site-/region-specific geologic and operational factors, NDIC may require additional information for permit approval. Therefore, the review of the relevant statutes and regulations in collaboration with NDIC representatives, other regulating authorities, and project partners is strongly recommended prior to submittal to ensure proper interpretation of APD and SFP application requirements and to ensure these requirements are adequately addressed. In addition, CO_2 storage incentive programs may have different (or potentially conflicting) requirements from those required for permitting compliance. Therefore, including program administrators in collaborations during the development stages of a CCS project is also recommended to ensure project compatibility with any potential incentive programs.

1.2 Template Terminology (see also Figure 1-1)

Numerous terms-of-art are used throughout the North Dakota statutes and regulations that require definition to ensure the proper interpretation of the permit requirements. A list of these terms is provided here. In addition, Figure 1-1 is provided specifically to present a simplified view of the regulatory terminology which establishes specific boundaries based on notification requirements and permit evaluation areas. The areas and zones in Figure 1-1 are identified and defined among the terms in this section.

- area of review (AOR) – region surrounding the geologic sequestration project where underground sources of drinking water (USDWs) may be endangered by the injection activity (NDAC 43-05-01-01 §4).

AOR: defined by the UIC program, establishes the boundaries of required long-term monitoring and emergency response plans.

- capillary pressure – the pressure required to move a fluid from a capillary or a pore space. It is a function of the properties of the fluid and surface and the dimensions of the space. The fluid is held in place if the attraction between the fluid and surface is greater than the interaction of fluid molecules (75 FR [Federal Register] 77229).

- carbon dioxide – produced by anthropogenic sources which is of such purity and quality that it will not compromise the safety of geologic storage and will not compromise those properties of a storage reservoir that allow the reservoir to effectively enclose and contain a stored gas (NDCC 38-22-02 §1).

- confining zone – a geologic formation, group of formations, or part of a formation stratigraphically overlying the injection zone that acts as a barrier to fluid movement. For injection wells operating under an injection depth waiver, confining zone means a geologic formation, group of formations, or part of a formation stratigraphically overlying and underlying the injection zone (NDAC 43-05-01-01 §11).

- emergency event – an event that poses either 1) an immediate (or acute) risk to human health, resources or infrastructure or 2) a potential (or chronic) risk to these same receptors should conditions worsen or no mitigative/remedial emergency responses be taken.

- CO_2 plume extent – the areal extent that will be occupied by geologically stored CO_2 over the life of the project as defined by geologic modeling and dynamic simulation (i.e., following injection cease and stabilization of the plume).

pore space amalgamation: The storage facility area consists of the CO_2 plume extent (as previously defined) plus a 0.5-mile buffer (NDCC 38-22-08 §12); this is the area that will be considered by NDIC for pore space amalgamation. Pore space amalgamation is the administrative process defined by North Dakota statute that grants the Commission the authority to permit CO_2 storage facilities and to require that the pore space owned by nonconsenting owners be included in a storage facility and subject to geologic storage (NDCC 38-22-10). The storage operator is mandated by law to obtain the consent of persons who own at least 60% of the storage reservoir's pore space (NDCC 38-22-08 §4). The law also mandates the storage operator make a good-faith effort to obtain consent from all persons who own the storage reservoir's pore space (NDCC 38-22-08 §4).

- facility area – areal extent of the storage reservoir (NDAC 43-05-01-01 §16).

- incident – events that do not pose either an acute or chronic risk to human health, resources, or infrastructure and do not warrant emergency responses.

- injection zone – a geologic formation, group of formations, or part of a formation that is of sufficient areal extent, thickness, porosity, and permeability to receive CO_2 through a well or wells associated with a geologic sequestration project (NDAC 43-05-01-01 §27).

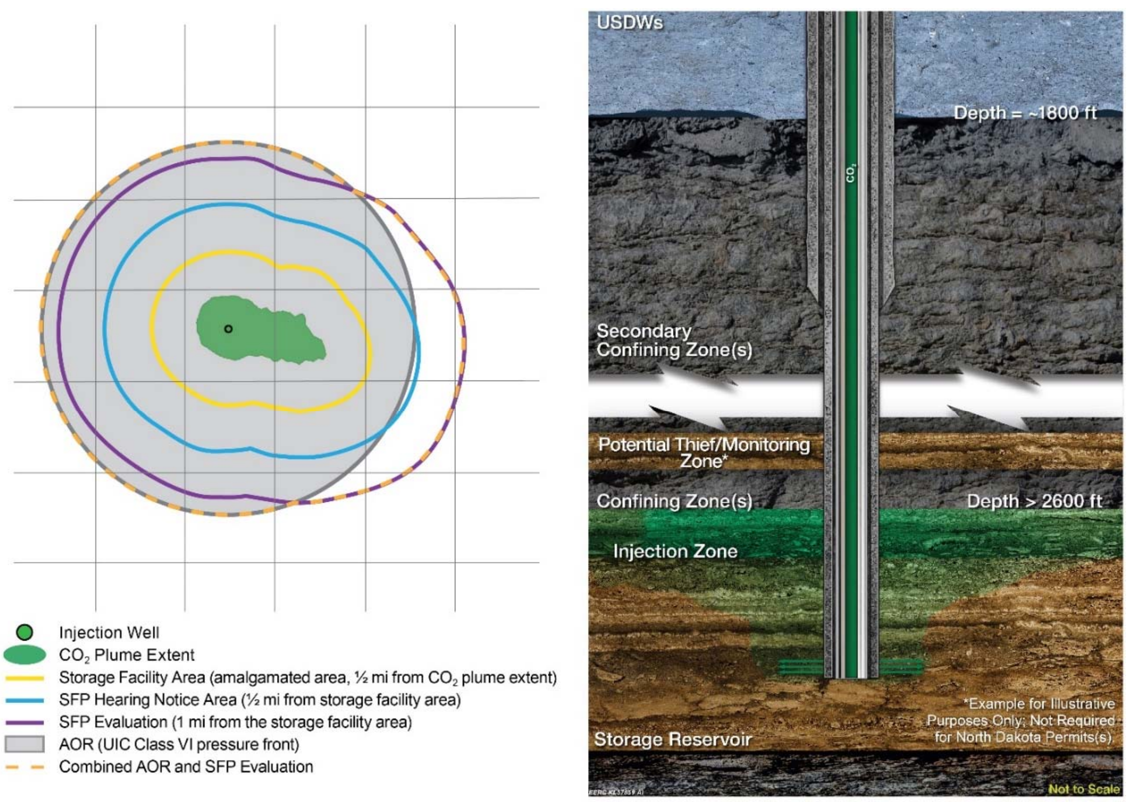


Figure 1-1. Surface (left; modified from DMR) and subsurface (right) areas/zones relevant to APD and SFP permit requirements for CCS projects in North Dakota.

- maximum acceptable pressure front – the critical reservoir pressure at which the magnitude of brine leakage into an USDW would exceed a certain threshold level based on the no-endangerment requirement (i.e., the level at which water quality impacts in the USDW could be expected plus a safety factor).

- pressure front – the zone of elevated pressure and displaced fluids created by the injection of CO_2 into the subsurface. The pressure front of a CO_2 plume refers to a zone where there is a pressure differential sufficient to cause the movement of injected fluids or formation fluids into USDW (NDAC 43-05-01-01 §38).

pressure front: the pressure required to raise the formation fluids to a USDW.

- pore space – a cavity or void, whether natural or artificially created, in a subsurface sedimentary stratum (NDCC 38-22-02 §5).

pore space: open spaces in rock or soil. These are filled with water or other fluids such as brine (i.e., salty fluid). CO_2 injected into the subsurface can displace preexisting fluids to occupy some of the pore spaces of the rocks in the injection zone.

- storage facility – the reservoir, underground equipment, and surface facilities and equipment used or proposed to be used in a geologic storage operation. It does not include pipelines used to transport CO_2 to the storage facility (NDCC 38-22-02 §7).

- storage reservoir – a subsurface sedimentary stratum, formation, aquifer, cavity, or void, whether natural or artificially created, including oil and gas reservoirs, saline formations, and coal seams suitable for or capable of being made suitable for injecting and storing CO_2 (NDCC 38-22-02 §8).

- thief zone – a formation between the storage unit and the USDW with higher permeability that could accept fluids (CO_2 or brine) and thus reduce the potential vertical flux of these fluids from a storage reservoir to overlying units.

- underground sources of drinking water (USDW) – an aquifer or any portion of an aquifer that supplies drinking water for human consumption, or in which the groundwater contains fewer than 10,000 milligrams per liter total dissolved solids and is not an exempted aquifer as determined by the Commission under NDAC 43-02-05-03 (NDAC 43-05-01-01 §45).

2.0 WELL-DRILLING PERMIT

For the purposes of this template, the APD has been developed as a stratigraphic test well APD template. A complete storage facility permit requires data and information obtained from core, geologic formation testing and sampling, and wireline logging within the facility area of a geologic storage project. While there may be instances where existing data (i.e., core and log data) can be used for the SFP in lieu of drilling a stratigraphic test well, in many cases the operator will need to drill a well prior to applying for an SFP to collect the necessary data.

Stratigraphic Test Well Design Options

1) Traditional test well that will be openhole-plugged after all of the necessary data, testing, and sampling have been collected.
2) A test well that has been constructed to UIC Class VI standards and designed for later conversion to a future Class VI-compliant CO_2 injection well. Core, geologic formation testing and sampling, and wireline logging will be collected during drilling and well construction, as appropriate.
3) A test well that has been constructed to UIC Class VI standards and designed for later conversion to a future Class VI-compliant monitoring well. Core, geologic formation testing and sampling, and wireline logging will be collected during drilling and well construction, as appropriate.

An option for accelerating deployment of CCS is to permit and drill a stratigraphic test well designed and constructed in a manner that provides a pathway to convert the well to a UIC Class VI-compliant injection well (e.g., strategic use of CO_2-resistant materials). The stratigraphic test well transition pathway is addressed in this template, which includes a request for approval to convert the well to a CO_2 injection well and an application to inject CO_2. Within 1 year of drilling and construction, the storage operator has the option to apply for temporary abandoned observation (TAO) well status. The TAO status determination will be based on the demonstration of mechanical integrity witnessed by a representative from the Commission. The TAO status, if granted, is allowed for 1 year, with the potential to request extensions in 1-year increments. This process creates a transition pathway that accounts for the time it will take to receive all of the necessary regulatory approvals to ultimately begin injection operations.

2.1 Application for Permit to Drill (NDAC 43-02-03)

The APD comprises prepermit filings, APD information (i.e., both general and well-specific information), and APD attachments, all of which are entered into the NorthSTAR electronic permitting system. It is important that the data and information provided in the electronic form are consistent with the data and information that are presented throughout the application and in the APD attachments (e.g., the casing depth in the electronic form should be the same as the depth in the drilling prognosis and the casing program).

2.1.1 Prepermit Filings

The storage operator is required to complete and submit the following prepermit filings:

- An organization report (NDIC Form 2-NDAC 43-02-03-11). The exact entity name that is registered with the Secretary of State should be used in this filing.

- Submission of all APDs through NorthSTAR, access to which requires an established NorthSTAR account that can be obtained by registering a new organization through the NDIC's NorthSTAR webpage.

- The filing of a single-well plugging and reclamation bond of $50,000 with NDIC. As part of this effort, it is important that the storage operator communicate with NDIC's Bond Assistant and Permit Manager since an APD cannot be issued until the bond has been approved by NDIC (NDAC 43-02-03-15).

2.1.2 APD Information (NDAC43-02-0316)

The APD is required to be submitted through NorthSTAR, NDIC's electronic permitting system.

2.1.2.1 General Information

The general information required to complete the APD consists of the addresses and phone numbers of the operator and surface owners and the approximate date that the site work will start. The storage operator is required to provide evidence that the well is not located within 500 feet of an occupied dwelling. If the well is located within 1320 feet (i.e., ¼ mile) of an occupied dwelling, the applicant is required to provide an affidavit of mailing that documents the owners of all such dwellings has been notified (NDCC 38-08-05).

2.2 APD Attachments

Several attachments are required to be developed by the storage operator to complete the APD. These attachments are described in the remainder of this section in the order in which they will likely be reviewed by NDIC.

2.2.1 Attachment 1: Plat Package

The APD includes 1) an accurate well location plat certified by a registered surveyor showing the location of the proposed well with reference to the nearest lines of a governmental section and referenced to true north; 2) an accurate pad layout which indicates a cut-and-fill diagram and additional construction required, i.e., water bars, culverts, etc.; 3) a facility layout, i.e., location of surface facilities on well pad; and 4) road access to the well location. If drill cuttings will be buried on location (i.e., a dry-cuttings pit), the location of the dry-cuttings pit needs to be included on the facility layout plat. Typically, closed mud systems are utilized for drilling in North Dakota and drill cuttings are hauled away from the drill site and disposed of in a solid waste landfill. If a closed mud system will be utilized, the application needs to include the name and address of the solid waste landfill and a statement that a closed mud system will be used. Examples for a plat package are provided in Appendix A.

2.2.2 *Attachment 2: Geological Prognosis*

This attachment, a geological prognosis, presents such information as the estimated depth to the top of objective horizons (measured depths [MD]); the estimated depth to the top and thickness of important geologic markers such as members or zones potentially containing usable water, USDWs, oil, gas, or other valuable deposits; and the identification of the formation at total depth, including the identification of all potential confining layers above and below the zone of interest. Table 2-1 provides an illustrative example of a geological prognosis for a well drilled in the Williston Basin in North Dakota.

Table 2-1. Illustrative Example of Geological Prognosis for a Well Drilled in Western North Dakota (values are provided for illustrative purposes only and site-specific data are required for an actual APD); note that in some cases MD can be different than true vertical depth

Formation	Measured Depth, ft	True Vertical Depth, ft	Lithology
Fox Hills	1526	1526	USDW
Pierre	1826	1826	Shale (seal)
Greenhorn	3992	3992	Shale
Mowry	4415	4415	Shale
Inyan Kara	4770	4770	Sandstone, siltstone, and shale
Swift	5091	5091	Shale
Rierdon	5493	5493	Shale and carbonate
Piper Marker	5752	5752	Shale
Spearfish	5963	5963	Siltstone, sandstone, mudstone, and shale
Minnekahta	6100	6100	Limestone
Opeche	6108	6108	Shale (cap rock)
Broom Creek	6273	6273	Sandstone and dolomite
Amsden	6536	6536	Dolomite, sandstone, anhydrite, and limestone
Total Depth	6790	6790	Dolomite, sandstone, anhydrite, and limestone

2.2.3 *Attachment 3: Drilling Program and Prognosis*

The drilling program and prognosis provide the technical detail of the plans for drilling and completing the injection well. Examples of the information and content of this attachment are as follows:

- Proposed total depth (including MD and true vertical depth) to which the well will be drilled
- Estimated depth to the top of important geologic markers
- Estimated depth to the top of objective horizons
- Proposed drilling mud program for surface hole and vertical hole

- Proposed openhole and cased-hole logging program
- Proposed well testing, coring, and geologic characterization program
- Proposed casing program including size and weight
- Proposed depth and formation at which each casing string is to be set
- Proposed amount of cement and placement procedure to be used
- Estimated top of cement
- General completion procedure
- Other pertinent information

2.2.4 Attachment 4: Proposed Drilling Mud Program

The storage operator provides information regarding the proposed mud program for both the surface and production holes in this attachment. Examples of the information to include for the surface and production holes are provided in Tables 2-2 and 2-3, respectively. These tables should be completed as a representation of the proposed drilling mud program. It should be noted that the proposed mud program described here is generic. Additional detail will likely be available for inclusion in this attachment at the time of the actual submission of the APD based on the recommendations of the mud engineer and wellbore conditions.

Lessons Learned – Oil-Based Versus Saltwater Gel Drilling Fluids: Although an oil-based mud may be often favored by oil industry, saltwater gel-based mud may be used to drill the Class VI injection well. Using saltwater gel mud has additional benefits compared to an oil-based mud when drilling and coring the injection well, such as:

1) Low cost in terms of cost per barrel.
2) Stronger cement bond to the casing and formation that increases the likelihood of a quality cement bond.
3) Sandstone formation with native brine being more compatible with a saltwater gel mud than oil-based mud. Oil-based mud presents a potential risk of damage to saline formations, which may ultimately reduce injectivity (i.e., clogging pore throats in the sandstone) and/or negatively impact core and sample testing results.

Table 2-2. Illustrative Mud Program for Surface Hole (values are provided for illustrative purposes only, and site-specific data are required for an actual APD)

Drilling Fluid System	Measured Depth, ft	Mud Weight, ppg	Yield Point, lb/100 ft^2	Funnel Viscosity, sec/qt	Chlorides, mg/L
Freshwater	0–1926	8.4–9.0	1–2	27–40	<5%

Table 2-3. Illustrative Mud Program for Production Hole (values are provided for illustrative purposes only, and site-specific data are required for an actual APD)

Drilling Fluid System	Measured Depth, ft	Mud Weight, ppg	Yield Point, lb/100 ft²	Plastic Viscosity, cP	Chlorides, mg/L	API Fluid Loss, cm³
Saltwater Gel	1926–6790	9.8–10.4	10–14	6–8	165,000–180,000	<10

2.2.5 Attachment 5: Casing Program (NDAC 43-02-03-21)

This attachment will include a description of the casing program, which includes the casing properties. Surface casing is required to be set at least 50 feet below the base of the lowest USDW (e.g., Fox Hills Formation). For well design, it is recommended to propose 100 feet of surface casing below the base of the USDW to ensure compliance with the 50-ft requirement (i.e., design surface casing to be set 100 feet into the Pierre Formation). Examples of the information to include in the casing program and casing properties are described in Tables 2-4 and 2-5, respectively. Tables 2-4 and 2-5 provide an example of the site-specific casing program information and casing properties required in the APD submittal.

Table 2-4. Illustrative Description of Casing Program (values are provided for illustrative purposes only, and site-specific data are required for an actual APD)

Section	Hole Size, in.	Casing OD, in.	Weight lb/ft	Casing Seat	Casing Seat MD, ft	Grade, Connection	Objective
Surface	13½	9⅝	36	Pierre	1926	Carbon steel, STC[1]	Cover shallow freshwater aquifers
Production	8¾	7	29	Amsden	6790	Carbon steel, LTC[2]; CO_2-resistant premium thread	Production casing

[1] Short Thread Coupling.
[2] Long Thread Coupling.

Table 2-5. Illustrative Description of Casing Properties (values are provided for illustrative purposes only and site-specific data are required for an actual APD)

OD,[1] in.	Grade	lb/ft	Connection	ID,[2] in.	Drift, in.	Burst, psi	Collapse, psi	Yield Strength (1000 lb)	
								Body	Connection
9⅝	Carbon steel	36	STC	8.921	8.765	3520	2020	564	453
7	Carbon steel	29	LTC	6.184	6.059	8160	7030	676	587
7	CO_2-resistant	29	Premium thread	6.184	6.059	8160	7030	676	676

[1] Outer diameter.
[2] Inner diameter.

Casing and Cement: CO_2-resistant casing and cement are not required for the entire wellbore (e.g., surface casing and cement is not required to be CO_2-resistant). The well needs to be designed and constructed to withstand the effects of the CO_2. CO_2-resistant materials are required by NDIC for any portion of the well that will be in or near direct contact with the injected CO_2, such as the tubing and packer the sections of casing and cement located in the injection zone and upper confining zone, etc.

2.2.6 Attachment 6: Cement Proposal (NDAC 43-02-03-21)

Table 2-6 is an example of the cement types and properties that are required as part of the APD.

Table 2-6. Illustrative Cement Proposal (values are provided for illustrative purposes only, and site-specific data are required for an actual APD)

Casing, in.	Tail		Lead		Planned Excess, %	Planned Volume, sacks
	Slurry	Top, ft	Slurry	Top, ft		
9⅝	Class “G” cement	1426	Class “G” cement	Surface	75	915
7	CO_2-resistant cement	5950	Class “G” cement	Surface	75	780

2.2.7 Attachment 7: Illustrative Wellbore Schematic

The storage operator is required to provide a schematic of the wellbore in this Attachment of the APD. An illustrative example of one such schematic for an injection well is provided in Figure 2-1.

2.2.8 Attachment 8: Coring, Testing, and Logging Program

An evaluation program for the coring, testing, and logging of the stratigraphic test well is provided in this attachment. Additional information of importance includes the descriptions of the pressure control equipment, the drilling procedure, and the postcompletion plan. Examples of the content that is required for each of these topics is provided in the remainder of this section.

NDIC-Stated Coring Preference: Include the collection and analysis of geologic core through the CO_2 storage injection zone and a minimum of 50 ft from the overlying and underlying confining zones. This is not a requirement but rather a recommendation from the NDIC. The purpose of this recommendation is to demonstrate the depth and characteristics of the geology as it transitions between rock types from the target injection zone (i.e., impermeable lithology in the confining zones to a porous, permeable lithology in the injection zone). There can be porosity intervals above and below the Inyan Kara and Broom Creek Formations as the rock type transitions. Collection of sufficient core of the confining zones will aid the operator in demonstrating upper and lower confinement.

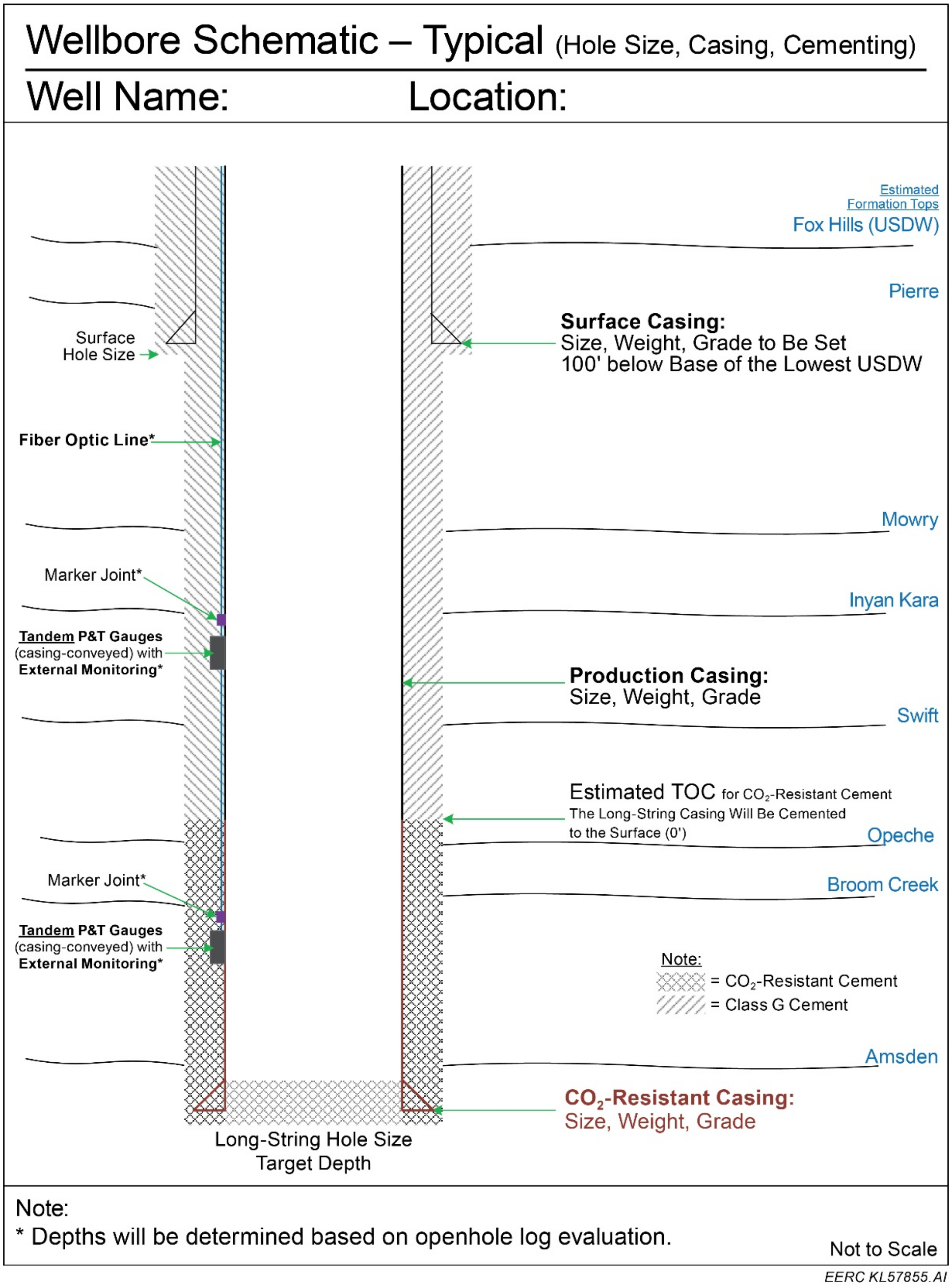


Figure 2-1. Illustrative example of a Class VI injection wellbore schematic.

2.2.8.1 Geologic Evaluation Program

Examples of the summary information for inclusion in the stratigraphic test well geologic evaluation program are as follows:

- Mudlogging – a process of capturing rock sample cuttings from the return mud stream during well drilling and subsequent documentation (i.e., logging) of geologic name, lithology, mineral analyses, and oil and gas shows by depth. The APD includes a description of the depth interval that will be covered by the mud log and the intervals at which sample cuttings will be obtained.

- Cores – specifies the formations from which cored sample intervals will be obtained using specialty drilling tools.

- Wireline logging – describes the openhole and cased-hole electrical and mechanical logging program that will be performed on both surface and long-string sections. Examples of the type of logs and information required include the following:
  - Openhole logging – Resistivity, spontaneous potential (SP), porosity, gamma ray (GR), and caliper logs are required by NDIC on both surface and long-string sections from total depth to the surface. Additional logs (e.g., acoustic, spectral GR, fracture finder, and fluid sampling) are also recommended in the long-string section for reservoir characterization.
  - Cased-hole logging – To determine if the cement has been set over the casing, NDAC 43-05-01-11.2 requires a radial cement bond log (RCBL), variable-density log (VDL), casing collar locator (CCL), temperature, and GR log.

NDIC-Stated Logging Preference: An ultrasonic CBL run on the long-string casing is preferred by NDIC to meet both the RCBL requirement and the requirement to demonstrate external mechanical integrity.

- Wireline formation tester – specifies the formations that will be subjected to this type of formation pressure test and fluid sampling.

- Drillstem testing (DST) – specifies the formations that will be subjected to this type of test which mechanically isolates the formation for pressure and fluid sampling.

- Other testing methods, if proposed, are provided.

Should additional tests be proposed as part of this evaluation program, a description of these topics is provided in this APD attachment.

2.2.8.2 Pressure Control Equipment (NDAC 43-02-03-23)

Well control during all phases of the drilling, logging, casing runs, cementing, testing, etc., is mandated by NDIC and by industry best management practices. Well control equipment is typically referred to as blowout prevention equipment (BOPE). The BOPE includes a description, accompanied by exhibits, of the type of equipment that will be used, e.g., blowout preventers, choke manifolds, and accumulators, including the operational procedures and frequency for testing and documentation of this equipment. An illustrative example of BOPE is provided in Figure 2-2.

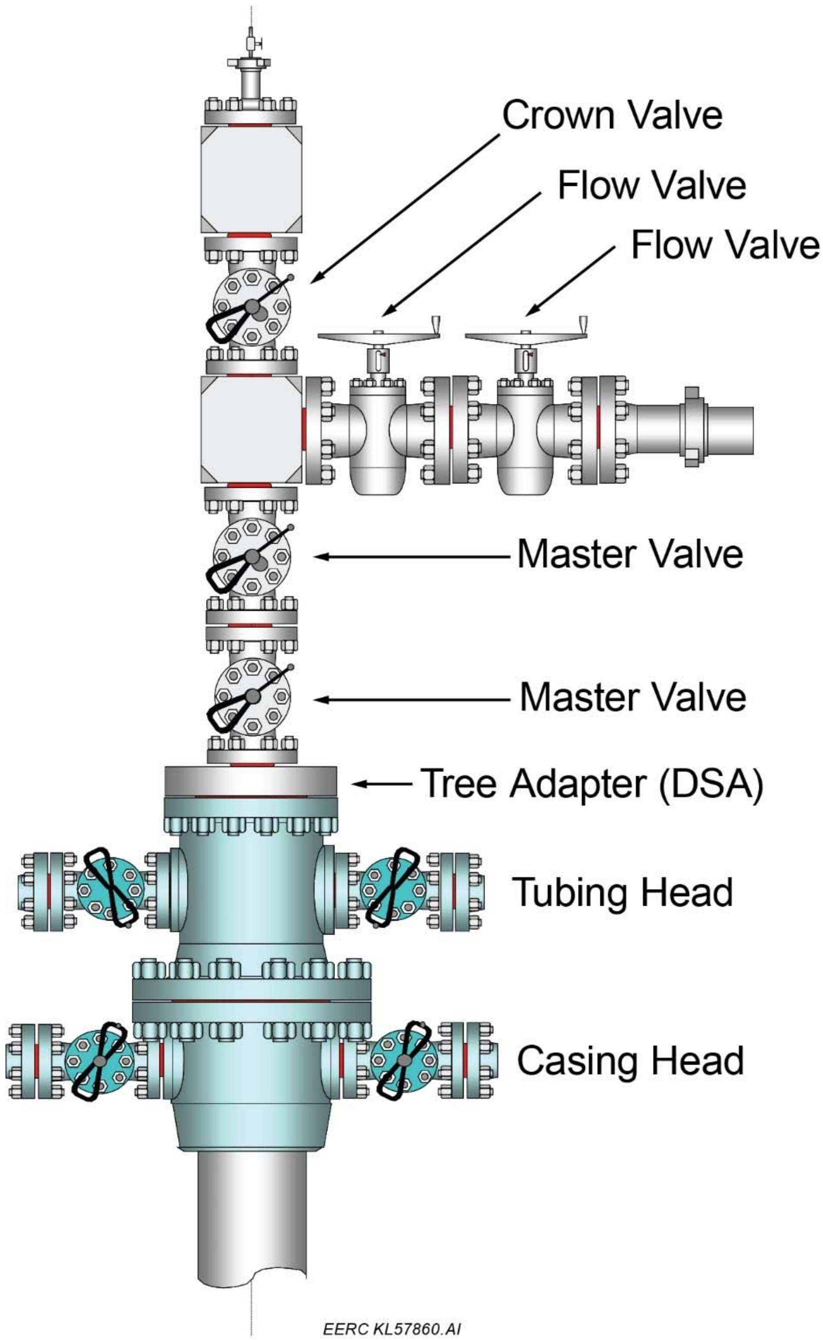


Figure 2-2. Illustrative example of wellhead and BOPE schematic for an injection well (modified from Schlumberger).

2.2.8.3 Drilling Procedure

Examples of the information included in the drilling procedure, which is required for each drilling interval from ground level to the total depth of the well, include the following:

- Hole size
- Type of drilling mud
- Bit and casing specifications
- Detailed drilling procedure
- Detailed coring, testing, and logging procedures
- Specific cementing procedures
- Cementing and casing evaluation procedures (NDAC 43-05-01-11.2)

2.2.8.4 Postcompletion Program (NDAC 43-05-01-09 §3)

Within 30 days after the conclusion of well drilling and completion activities, the storage operator is required to provide project-specific reports, exhibits, documentation, and descriptions of the drilling, logging, coring, cementing, and well integrity evaluations of the stratigraphic test well.

2.2.8.5 Logging and Testing Program (NDAC 43-05-01-11; NDAC 43-02-03-38.1)

During the drilling and construction of a stratigraphic test well, the storage operator is required to provide documentation and exhibits that demonstrate that appropriate logs, surveys, and tests were performed to determine or verify such information as the depth, thickness, porosity, permeability, lithology, and salinity of any formation fluids in all relevant geologic formations. These data are necessary to ensure conformance of the well construction with the requirements under NDAC 43-05-01-11 and to establish accurate baseline data against which future measurements may be compared. The storage operator is also required to submit to the Commission a descriptive report prepared by a log analyst that includes an interpretation of the results of such logs and tests.

Examples of the details of the coring, logging, and testing program that are required to comply with these requirements are discussed.

Table 2-7 provides examples of the type of information that should be considered as part of the proposed coring program. Included in this information is the identification of the coring interval, the specification of the formations from which the interval was taken, and a description of the core, e.g., diameter and length.

Table 2-7. Illustrative Example for Coring Program Details (values are provided for illustrative purposes only and require replacement)

Interval Identification	Source of Core	Description of Core
X feet to Y feet	Formation Name	Cylindrical (with dimensions)
6223–6586	Broom Creek	4-in. whole core

2.2.9 Attachment 9: Coring Program (NDAC 43-05-01-11.2 §2)

It should be noted that NDIC may require the storage operator to core specific formations in the borehole. To the extent that these requirements are anticipated, all such coring events should be included in this description of the coring program.

Core Requirements: North Dakota requires (NDCC 38-08-04 and NDAC 43-02-03-38.1) all core to be shipped to the state's core library within 180 days of completion of drilling operations. The North Dakota Geological Survey's Wilson M. Laird Core and Sample Library is located on the University of North Dakota campus in Grand Forks. A request for an extension can be made on a Form 4 Sundry Notice. Core analysis is also required to be submitted to the NDIC 30 days following completion of the analysis. A request for extension of time can also be made for the analysis submission.

Logging and Testing Program (NDAC 43-05-01-11.2 §1b and §1c)

A logging and testing program for both the open- and cased-holes is provided in this attachment. An illustrative example of a testing and coring program associated with the well drilling is provided in Figure 2-3. Examples of the type of information provided by these logs and tests are as follows:

- Logging and testing before and upon installing the surface casing: 1) resistivity, spontaneous potential, and caliper logs before the casing is installed; 2) an RCBL and VDL to evaluate cement quality radially; and 3) a temperature log after the casing is set and cemented.

    - Logging and testing before and upon installation of the production (long-string) casing: 1) resistivity, spontaneous potential, porosity, caliper, GR, fracture finder logs, and any other logs the Commission requires for the given geology before the casing is installed; 2) an ultrasonic CBL (see previous callout box "NDIC-Stated Logging Preference") and VDL; and 3) a temperature log after the casing is set and cemented.

Table 2-8 provides an example of the logging and testing details that will be used to demonstrate compliance with the permit requirements. Note that the GR log must be run to ground level and the CBL run on the intermediate or production casing.

2.2.10 Attachment 10: Other Requirements

Other project-specific considerations may need to be accounted for as part of the APD. The storage operator needs to demonstrate that there are no conflicts with the NDIC drilling permit review policy (NDIC-PP) by providing evidence with a complete APD submittal that all documents follow NDIC regulations and permit requirements.

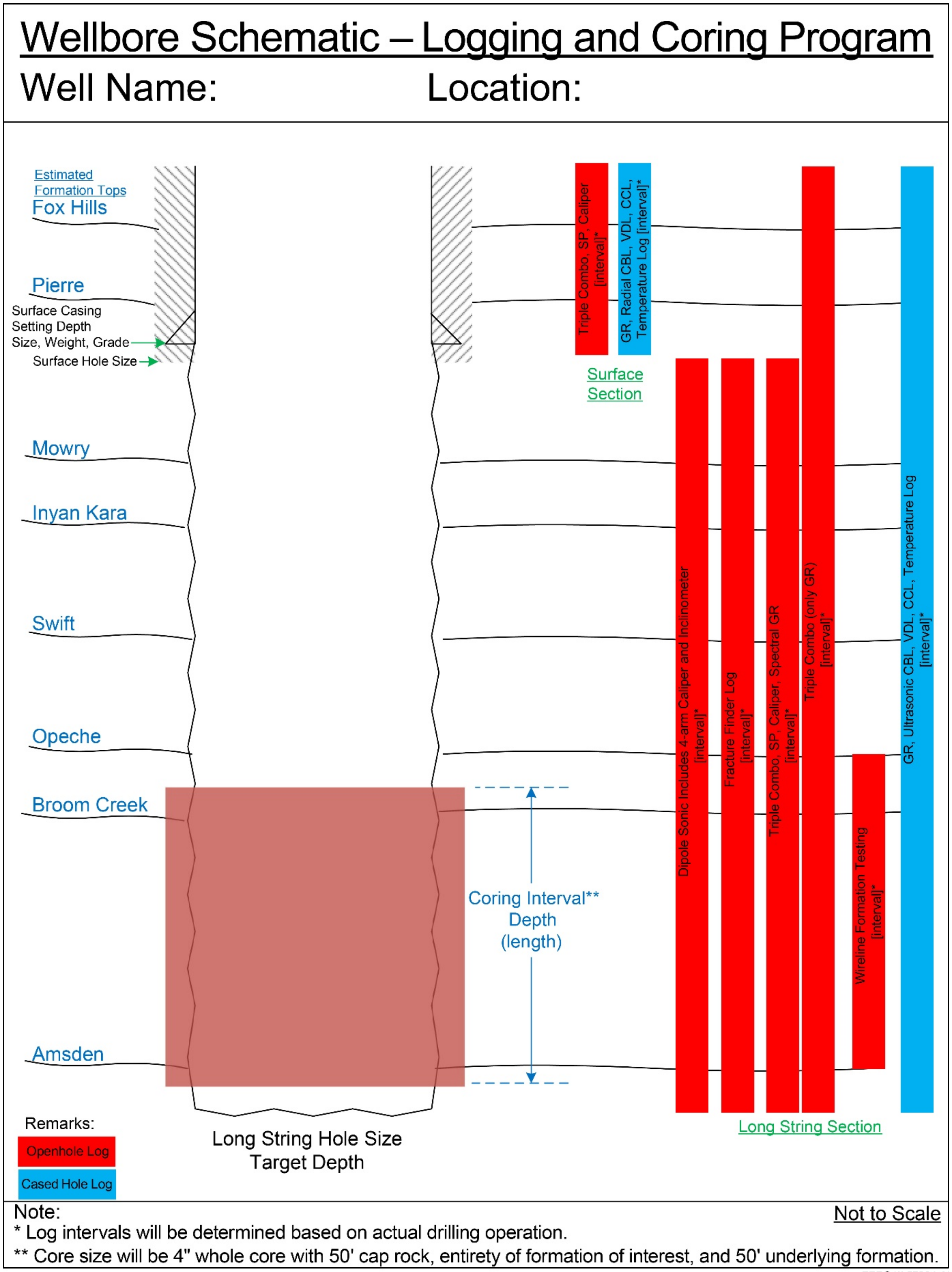


Figure 2-3. Illustrative example of the logging and coring program.

Table 2-8. Example for Logging and Testing Program Details (values are provided for illustrative purposes only and require replacement)

Type	Description	Depth Intervals	Justification
Triple-Combo, Caliper and SP	Surface section – openhole	1926–0	Quantify variability in reservoir properties. Identify wellbore volume to calculate cement volume.
RCBL–VDL–CCL–GR–Temperature Log	Surface section – cased hole	1926–0	Identify cement bond quality radially. Detect if cement channels exist. Evaluate the cement top and zonal isolation.
Triple-Combo, SP, Dipole Sonic (with 4-arm caliper), Spectral GR, Fracture Finder Log, Wireline Formation Testing	Long-string section – openhole	6790–1926	Determine depth, thickness, porosity, permeability, lithology, and salinity of any formation fluids. Dipole sonic and the fracture finder log quantify if fractures exist in the Broom Creek Formation and the confining layer. Wireline formation testing collects reservoir fluid from the Broom Creek Formation for testing of potential fluid and mineralogical reactions between injected fluid and formation fluid chemistry. This test can provide accurate real-time reservoir pressure measurements, permeability measurements, and can also provide the minimum in situ stress magnitude of formation by performing a mini-frac test/s.
Ultrasonic CBL–VDL–CCL–GR–Temperature Log	Long-string section – cased hole	6790–0	Identify cement bond quality radially. Detect if cement channels exist. Evaluate the cement top and zonal isolation.

3.0 STORAGE FACILITY PERMIT (NDAC 43-05-01 Geologic Storage of Carbon Dioxide)

This template for the SFP application provides a description of what is required in each section of the permit application to comply with the applicable portions of the NDCC and NDAC; however, the template does not necessarily describe how to prepare the specific materials, maps, or technical exhibits. The template represents an overview of the topics and types of information that are needed to populate an SFP application, which includes the following five sections: 1) pore space access, 2) geologic exhibits, 3) AOR exhibits, 4) supporting permit plans, and 5) injection well and storage operations. These five sections should be presented in this order as it comports with the general order of presentations that are typically made during the testimony provided at the administrative hearing, which is part of the regulatory process required for approval of the SFP application.

A good working knowledge of the appropriate NDCC, NDAC, and other NDIC policies and guidelines is required to prepare and submit a successful SFP application. A crosswalk between the primary sections of the SFP application template and the relevant portions of the NDCC and NDAC is provided in a table in Appendix B of this document. For each section of the application, the applicable portion of the NDAC and NDCC is listed along with the specific requirements that are embodied in the statute and/or regulations. This crosswalk ensures the generation of a compliant SFP application.

A cover letter accompanying the SFP application package should be filed with the NDIC in order to begin the regulatory review process. Upon SFP application submission, the NDIC will perform an initial review to determine whether the application is complete. The NDIC has 1 year from the date the SFP application is deemed complete to issue a final decision regarding the application. The remainder of this section of the template describes in detail the contents of each major section of the SFP application.

3.1 Pore Space Access (NDCC 38-22-08 §4, §5, and §14; NDCC 38-22-10; and NDAC 43-05-01-08 §1 and §2)

North Dakota law explicitly grants title of the pore space in all strata underlying the surface of lands and waters to the overlying surface estate, i.e., the surface owner owns the pore space (NDCC 47-31 Subsurface Pore Space Policy). Furthermore, prior to initiating the storage of CO_2, the North Dakota statute for the geologic storage of CO_2 mandates that the storage operator obtain consent of landowners who own at least 60% of the pore space of the storage reservoir. The statute also mandates a good faith effort be made to obtain consent from all pore space owners and that all nonconsenting pore space owners are or will be equitably compensated. North Dakota law grants NDIC the authority to require pore space owned by nonconsenting owners to be included in a storage facility and subject to geologic storage through pore space amalgamation. Amalgamation of pore space will be considered at the administrative hearing as part of the regulatory process required for consideration of the SFP application.

This section of the SFP is focused on the notification process and conduct of a hearing before the Commission that involves the CO_2 storage operator and the parties that are involved in the pore space amalgamation process. The information that is required at the hearing to support the pore space amalgamation process is also described.

3.1.1 Proof of Notification

The Commission will notify the CO_2 storage operator when a pore space amalgamation hearing date is scheduled on the docket. Upon receiving that notification, the CO_2 storage operator is required to notify all owners (surface and mineral), mineral lessees, and any operator of mineral extraction activities within the facility area and within 0.5 mile of its outside boundary. The notification includes information about the proposed CO_2 storage project, details of the scheduled hearing, and a statement that the Commission will address pore space amalgamation at the hearing. The CO_2 storage operator is required to provide the Commission with an affidavit of mailing to certify that these notifications have been made. This notice must be given to each mineral lessee, mineral owner, and pore space (surface) owner at least 45 days prior to the hearing.

3.1.2 Pore Space Owner and Lessees

The CO_2 storage operator is required to identify all the owners and lessees that need to be notified and all pore space owners involved in the amalgamation process. This can best be demonstrated by creating multiple maps, examples of which are provided below:

- A map showing the extent of the pore space that will be occupied by CO_2 over the life of the project.

- A map with the legal descriptions showing the extent of the CO_2 plume.

- Quarter-by-quarter, pore space (surface) ownership maps with an ownership legend if landownership is in small parcels and complex.

- A series of maps showing the storage reservoir boundary and 0.5 mile (0.8 kilometers) outside of the storage reservoir boundary with a description of:
  - Pore space ownership, surface owner, and pore space lessees of record.
  - Each operator of mineral extraction activities by type, e.g., coal, oil and gas, etc.
  - Each mineral lessee of record.
  - Each owner of record of minerals.

3.2 Geologic Exhibits

Geologic and hydrogeologic technical evaluations of the carbon storage project area are required as part of the SFP. More specifically, these technical exhibits should include information such as the geologic evaluations of the injection zone, confining zones, and storage reservoir and a hydrogeologic evaluation of underground sources of drinking water. These technical evaluations may include a combination of written technical descriptions, geologic exhibits, and relevant maps of the project area, as discussed further in the remainder of this section.

3.2.1 Introduction

An overview of the geological characteristics of the storage project can be provided by utilizing exhibits such as a topographic map of the project area showing key geographic information, a stratigraphic column identifying the key geologic formations within the project area, and cross section (or cross sections) of the geologic formation into which the CO_2 will be injected, i.e., injection zone. It would also be useful to identify the surface location of the CO_2 injection well on the cross sections.

To aid in their interpretation, a brief written description of the regional geology and the geology of the storage reservoir may be developed to accompany the exhibits. The latter includes information such as the formation names, the lithology, the average depth and thickness of the storage reservoir in the project area, and source references.

3.2.2 Injection Zone

3.2.2.1 Description of Injection Zone

The targeted injection zone is described in detail in this section of the template including information such as described in Table 3-1 and, if necessary, using exhibits as listed below to aid in the understanding of the information in the table:

- An areal (e.g., satellite image) map and a surface (e.g., section, township, range, etc.) map that show the areal extent of the injection zone formation.

- A map from the geologic model of the site that provides a visual depiction of facies changes in the injection zone accompanied by a brief description.

Use of fence diagrams, which are derived from a combination of logs from existing wells in the project area and modeled type logs, may also be considered to visually depict the facies changes across the project area.

Table 3-1. Description of CO_2 Injection Zone (values are provided for illustrative purposes only and require replacement)

<table>
<tr><th colspan="3">Injection Zone Properties</th></tr>
<tr><th>Property</th><th colspan="2">Description</th></tr>
<tr><td>Formation Name</td><td colspan="2">Broom Creek</td></tr>
<tr><td>Lithology</td><td colspan="2">Sandstone, dolomite</td></tr>
<tr><td>Formation Top, ft</td><td colspan="2">6273</td></tr>
<tr><td>Thickness, ft</td><td colspan="2">263 (sandstone 152, dolomite 169)</td></tr>
<tr><td>Capillary Pressure, psi</td><td colspan="2">0.69 (gas–water system)</td></tr>
<tr><th colspan="3">Geologic Properties</th></tr>
<tr><th>Formation</th><th>Property</th><th>Description</th></tr>
<tr><td rowspan="2">Broom Creek (Sandstone)</td><td>Porosity, %</td><td>21.97 (10.22–31.53)</td></tr>
<tr><td>Permeability, mD</td><td>193.87 (17.62–1677.49)</td></tr>
<tr><td rowspan="2">Broom Creek (Dolomite)</td><td>Porosity, %</td><td>10.08 (3.39–17.09)</td></tr>
<tr><td>Permeability, mD</td><td>1.026 (0.02–40.67)</td></tr>
</table>

3.2.2.2 Geochemical Information of Injection Zone

A discussion of the predicted interaction and compatibility of the CO_2 stream within the formation following its injection is required. The primary interactions of interest are absorption, dissolution, and mineralization processes. A report describing the findings, testing methods performed, and quality assessment and quality control will be included in this portion of the SFP application.

3.2.2.3 *Identification of Data and Information Sources*

It is important to identify the source of the data and information used to characterize the injection zone (e.g., core data, geophysical data, well logs, outcrop), distinguishing between those data and information that were collected as part of the geologic site characterization for the project (e.g., core, logs, seismic) from those data that were obtained from other available information (e.g., nearby well logs, research papers, previously acquired existing seismic, etc.). A report describing these findings will be included in this portion of the SFP application.

3.2.3 Confining Zone

3.2.3.1 *Description of Upper and Lower Confining Zones*

The upper and lower confining zones associated with the storage reservoir can be described using information such as that presented in Table 3-2, which includes information for both zones such as:

- Depth of the formation tops.
- Thickness.
- Mineralogy.
- Porosity (average and range) and permeability (average and range).
- Capillary pressure.

Table 3-2. Description of Depositional Environment of Upper and Lower Confining Zones (values[1,2] are provided for illustrative purposes only and require replacement)

Confining Zone Properties		
	Description	
Property	**Upper Confining Zone**	**Lower Confining Zone**
Formation Name	Opeche	Amsden
Lithology	Siltstone/shale	Dolomite/shale
Formation Top, ft	6108	6536
Thickness, ft	165	101
Porosity, %	9.45 (0.1–16.0)	7.86 (0.1–29.3)
Permeability, mD	0.21 (0.02–1.5)	0.04 (0.001–178.0)
Capillary Entry Pressure, psi	3000	185.85
Depth below Lowest Identified USDW, ft	4282	4710

[1] Sorensen, J.A., Smith, S.A., Dobroskok, A.A., Peck, W.D., Belobraydic, M.L., Kringstad, J.J., and Zeng, Z., 2009, Carbon dioxide storage potential of the Broom Creek Formation in North Dakota—a case study in site characterization for large-scale sequestration, *in* Grobe, M., Pashin, J.C., and Dodge, R.L., eds., Carbon dioxide sequestration in geological media—state of the science: AAPG Studies in Geology 59, Tulsa, OK, American Association of Petroleum Geologists, p. 279–296.

[2] Center for Economic Geology Research website, (2020) www.uwyo.edu/cmi/_files/docs/de-fe0009202.pdf (accessed 2020).

Exhibits similar to those provided for the injection zone will provide the data for both the upper and lower confining zones, as listed below:

- A surface map that shows their areal extent.
- A map from the geologic model of the site that provides a visual depiction of facies changes, accompanied by a brief description.

Use of fence diagrams, which are derived from a combination of logs of existing wells in the project area and modeled type logs, should also be considered to visually depict the facies changes in these confining zones across the project area.

3.2.3.2 Geomechanical Information of Confining Zone

A description of the geomechanical characteristics of the confining zone will provide evidence that the confining zone is free of transmissive faults or fractures and is of sufficient areal extent and integrity to contain the injected CO_2. The geomechanical description includes information on fractures, stress fields, ductility, rock strength, and in situ fluid pressure.

3.2.3.3 Faults, Fractures, and Seismic Activity

If there are known or suspected faults or fractures that may transect the confining zone in the AOR, provide evidence that the faulting or fracturing does not compromise the integrity of the storage reservoir. Specifically, the location and orientation of the faults/fractures should be provided along with an assessment of the probability that they would interfere with containment of the CO_2 and/or formation brine.

Additional information regarding tectonic activity at a regional level can provide a valuable perspective for understanding the faults, fractures, and seismic activity of the storage site. Similarly, providing a description of the seismic history, including the presence, depth, and frequency of seismic events in North Dakota will also provide valuable information. Presentation of this information in a report with exhibits including citations to specific scientific publications provides sufficient evidence necessary for the regulatory review.

Lastly, the seismic activity report will include examples of regional maps and cross sections to depict any faulting, fractures, and tectonic activity as well as a national seismic activity map to provide the proper context for the regional data and information.

3.2.3.4 Additional Confinement Beyond Immediate Confining Zones

It is important that all additional confining formations within the geologic storage system that lie above the immediate confining zones be identified and characterized by providing information such as presented in Table 3-3. In addition, consideration should also be given to providing a cross-sectional view that shows the location of these additional confining zones relative to the injection zone along with a statement that these additional confining formations are free of transmissive faults and, in combination with the immediate upper confining zone, are capable of preventing vertical movement into USDWs.

Table 3-3. Description of Zones of Confinement above the Immediate Upper Confining Zone (values are provided for illustrative purposes only and require replacement)

Name of Formation	Lithology	Formation Top, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Shale	1826	2166	0
Greenhorn	Shale	3992	423	2166
Mowry	Shale	4415	355	2589
Inyan Kara	Sandstone	4770	321	2944
Swift	Shale	5091	402	3265
Rierdon	Shale	5493	259	3667
Piper Kline	Limestone	5752	106	3926
Piper Picard	Shale	5858	105	4032
Spearfish	Siltstone	5963	137	4137
Minnekahta	Limestone	6100	8	4274

These confining zone analyses can be used to identify those that act as pressure dissipation zones (i.e., thief zones) and/or are targeted as monitoring zones for CO_2, temperature, pressure, water quality, etc.

3.2.3.5 Identification of Data and Information Sources

A written description of the geologic confinement characteristics and mechanisms, including the rock properties that prevent the migration of CO_2 beyond the storage reservoir, is an important element of the SFP. It is important that the source of the data and information used to characterize the upper and lower confining zones (e.g., core data, geophysical data, well logs, outcrop) be identified, distinguishing between those data and information collected as part of the geologic site characterization for the project (e.g., core, logs, seismic) from data obtained from other available information (e.g., nearby well logs, research papers, previously acquired existing seismic, etc.).

3.2.4 Storage Reservoir

A description of the storage reservoir can be accomplished using a combination of exhibits that include a discussion regarding the geologic structure and formation thickness. These exhibits should include information such as the identification of all geologic characteristics that control the isolation of stored CO_2 and associated formation fluids within the storage reservoir, including structural spill points and stratigraphic discontinuities. This evaluation needs to describe the storage reservoir's mechanisms of geologic confinement, including properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. A candidate list of the exhibits for consideration are as follows:

- Geologic structure
  - A visual depiction of confinement zones across the project area using logs from existing wells in the project area and modeled type logs using fence diagrams (see description of upper and lower confining zones).
  - A structure map of the formation top of the storage reservoir.
  - A structure map of the base of the formation of the storage reservoir.
  - A cross section of the storage reservoir showing any structural spill points and stratigraphic discontinuities.
  - Structural and stratigraphic cross sections that describe the geologic conditions of the storage reservoir.
- Formation thickness
  - An isopach map of the storage reservoir(s) thickness.
  - An isopach map of the primary containment barrier thickness (i.e., the upper confining zone) for the storage reservoir.
  - An isopach map of the secondary containment barrier(s) thickness for the storage reservoir.

3.2.5 Protection of USDWs

The primary purpose of this section is to provide information identifying the overall isolation and protection of the lowest USDW. Included in this section of the SFP is a discussion of the formation names, depths, and thicknesses of the geologic overburden along with the depth and length of each of the secondary seals above the injection zone. Information on the well penetrations in the area are provided in maps upon which the wells are identified. Well status, details on steel casing and cementing isolation, as well as the status of plugged and abandoned wells, which are essential to the protection of USDWs, are discussed in other sections of this template.

Brief descriptions and illustrations of the hydrogeology in the storage facility area, including the identification of key groundwater formations, should also be considered for inclusion in this section of the template by providing hydrogeologic maps and cross sections. Examples of the information included in these maps are listed below:

- A cross section of the groundwater formations showing general vertical and lateral limits across the project area.

- Identification of the different uses of the groundwater formations in the area (e.g., drinking water, stock water, irrigation water, etc.).

- Description of the expected groundwater quality for the various groundwater uses.

- Direction of groundwater flow.

Included in this section of the SFP is an areal map that shows the location of all groundwater wells across the project area identified by well type, i.e., water use. For reference, the wellsite and facility locations should also be shown on this map, and the distance from the closest groundwater wells to the injection well(s) needs to be clearly identified. If present, a brief description of the main source of drinking water for any nearby city or community should also be considered.

3.3 Area of Review Exhibits

The storage facility permit is required to define an AOR and contain a corrective action plan. The AOR of a CO_2 storage project is the region surrounding the proposed CO_2 injection well where USDWs may be endangered by the injection activity. The NDAC defines the AOR as the areal extent of the CO_2 storage reservoir, an area 1 mile outside of the CO_2 storage reservoir boundary, and the area encompassed by the maximum acceptable pressure front caused by injection activities. The regulations require that the AOR be delineated using computational modeling and that it be reevaluated periodically during the lifetime of the geologic storage project.

The corrective action plan focuses on the identification and evaluation of all wells within the AOR that penetrate the upper confining formation of the storage reservoir. If warranted, corrective action will be defined for those wells that represent potential leakage pathways of concern, and a schedule for the implementation of the corrective action, i.e., prior to injection or phased over time, should be presented.

3.3.1 AOR Delineation

The storage facility permit is required to have a separate section titled "Area of Review Delineation," which will require maps of the AOR as delineated using computational modeling. These maps include information such as all critical boundaries, the location of any proposed injection wells or monitoring wells, the presence of significant surface structures or land disturbances, and the location of water wells and any other wells. The specific requirements for this section include a written description accompanied by the supporting maps and tables.

3.3.1.1 Written Description

A written description of the method used for AOR delineation (i.e., methods and assumptions) is required along with a discussion of, and when, any corrective action would be needed. Plans for providing continued updates of the AOR delineation are also required. At a minimum, current regulations require that a reevaluation be done every 5 years during a state-required review of the permit. Included in the AOR delineation should be information such as 1) the computational model that is used, including specifics regarding all of the software that will be used; 2) the site characterization data and assumptions upon which the models are based; and 3) the integration of the areas of predicted CO_2 plumes and pressure fronts to produce a site-specific AOR. In addition, it is recommended that a permit section titled "Assumptions and Justification" be developed to present the reasoning that was used to support the assumptions that were made in the computational model.

Modeled interpretation of the pressure front and its potential impact on USDWs through the subsurface movement of CO_2 and/or brine is also an important part of this section of the SFP application. Critical supporting information of this effort includes information such as baseline geochemical data on subsurface formations, including all USDWs within the AOR (i.e., USDWs, water wells, and springs), as well as maps and stratigraphic cross sections of all USDWs within the AOR. The maps and cross sections should include details such as 1) the locations of the sources of drinking water relative to the injection zone; 2) the direction of water movement, where known; 3) and general vertical and lateral limits.

3.3.1.2 Supporting Maps

Several additional maps are required to provide support for the AOR delineation. Several examples of these maps, including a brief discussion of each, are provided below:

- AOR maps – The storage facility evaluation area includes the areal extent of the CO_2 storage reservoir and 1 mile outside of the CO_2 storage reservoir boundary, plus the extent of the maximum acceptable pressure front caused by injection activities, also known as the AOR. Examples of maps that depict the delineation of the AOR include:
  - Maps showing the injection well location, the injection zone contours, the areal extent of the CO_2 plume, the facility area (the plume area plus 0.5-mile buffer), the storage facility permit hearing notice boundary (1-mile AOR boundary beyond the CO_2 plume boundary), the pressure front-defined AOR boundary, and the AOR (pressure front plus 1.5-mile buffer).
  - Map of delineated AOR, which should include all boundaries, the location of any proposed injection wells or monitoring wells, key surface structures and land disturbances, the location of groundwater wells, and any oil and gas wells.
  - Maps showing the following within the combined AOR and SFP evaluation area:
    - ♦ All wells, including water, oil, and natural gas exploration and development wells, highlighting those wells that penetrate the storage reservoir or primary or secondary seals overlying the storage reservoir.
    - ♦ All other man-made subsurface structures and activities, including coal mines.
    - ♦ Areal extent of all man-made surface structures that are intended for temporary or permanent human occupancy.
    - ♦ Any productive existing or potential mineral zones occurring within the storage reservoir area and within 1 mile outside of its boundary.
  - A final map for the AOR that includes the following information:
    - ♦ Number or name and location of all injection wells
    - ♦ Number or name and location of all producing wells
    - ♦ Number or name and location of all abandoned wells
    - ♦ Number of name and location of all plugged wells or dry holes

        - ♦ Number or name and location of all deep stratigraphic boreholes
        - ♦ Identify any state-approved or U.S. Environmental Protection Agency (EPA)-approved subsurface cleanup sites
        - ♦ Identify surface bodies of water
        - ♦ Identify any springs
        - ♦ Name and location of all mines (surface and subsurface)
        - ♦ Name and location of all quarries
        - ♦ Identify all known water wells
        - ♦ Identify any other pertinent surface features
        - ♦ Identify all structures intended for human occupancy
        - ♦ Identify any state, county, or Indian country boundary lines
        - ♦ Identify all state and federal highways and county roads
    - – Should the AOR extend across state jurisdictions, it is required that a list of the state contacts be submitted to the Commission and included in the permit.

- CO_2 storage reservoir map – a map showing the following within the CO_2 storage reservoir:
    - – Boundaries of the CO_2 storage reservoir
    - – Location of all proposed wells
    - – Location of proposed cathodic protection boreholes
    - – Any existing or proposed aboveground facilities

3.3.2 Corrective Action Evaluation

A review of the wells identified in the AOR that penetrate the storage system is required along with a description of any necessary corrective actions and a schedule for their implementation. Included as part of the well assessment are activities such as the following:

- Documentation, such as the post-plugging report and the CBL, that all abandoned wells have been plugged in a manner that prevents the CO_2 or associated fluids from escaping the storage reservoir.

- A determination, such as an engineering review of well logs and construction records, and a statement that all operating wells have been constructed in a manner that prevents the CO_2 or associated fluids from escaping the storage reservoir.

- A description of each well which includes the following information:
    - – Well type (oil, gas, injection, storage)
    - – Well status (producing, shut-in, temporarily abandoned, plugged and abandoned)
    - – Date drilled
    - – Location (latitude/longitude and legal location)
    - – Depth
    - – Record of plugging, if appropriate, including:
        - ♦ Depth of plugs (top and bottom)
        - ♦ Type of plug placement (balanced plug, etc.)
        - ♦ Number of cement sacks

- ♦ Type of cement
- ♦ Displacement fluid (mud or water)
- – Record of completion including:
  - ♦ CBL evaluation
  - ♦ Cement top
  - ♦ Isolation across the injection zone (above and below injection zone)
  - ♦ Completed formation name
  - ♦ Completed or perforated interval
  - ♦ Current records or other pertinent information (tubing, packer, artificial lift equipment, etc.)

3.3.3 Reevaluation of AOR and Corrective Action Plan

It is required that the storage operator routinely reevaluate the AOR and corrective action plan, with the period between evaluations not to exceed 5 years. As part of the SFP, the application describes the following:

- Any monitoring and operational conditions that would warrant a reevaluation of the AOR prior to the scheduled 5-year reevaluation date.

- How monitoring and operational data (e.g., injection rate and pressure) will be used to inform a reevaluation of the AOR and corrective action plan, including how the computational model that was used to determine the AOR will be updated and what operational data will be used as the basis for that update.

- How corrective action, if necessary, will be conducted, including 1) what corrective action will be performed prior to, or following, injection and 2) how corrective action will be adjusted if there are changes in the AOR.

3.4 Supporting Permit Plans (NDACC 43-05-01-05)

Ten supporting plans are required as part of the SFP permit application. The required plans (with statutory reference) include the following:

- Emergency and Remedial Response Plan (NDAC 43-05-01-05 §1d; NDAC 43-05-01-13)

- Financial Assurance Demonstration Plan (NDAC 43-05-01-05 §1k; NDAC 43-05-01-09.1)

- Worker Safety Plan (NDAC 43-05-01-05 §1e; NDAC 43-05-01-13)

- Corrosion and Monitoring and Prevention Plan (NDAC 43-05-01-05 §1f; NDAC 43-05-01-15)

- Surface Leak Detection and Monitoring Plan (NDAC 43-05-01-05 §1g; NDAC 43-05-01-14)

- Subsurface Leak Detection and Monitoring Program (NDAC 43-05-01-05 §1h)
- Well Casing and Cementing Program (NDAC 43-05-01-05 §1i; NDAC 43-05-01-09)
- Testing and Monitoring Plan (NDAC 43-05-01-05 §1l; NDAC 43-05-01-11.4)
- Plugging Plan (NDAC 43-05-01-05 §1m; NDAC 43-05-01-11.5)
- Postinjection Site Care and Facility Closure Plan (NDAC 43-05-01-05 §1n; NDAC 43-05-01-19)

The required content of each of these plans is described in the remainder of this section.

3.4.1 Emergency and Remedial Response Plan (NDAC 43-05-01-05 § 1d; NDAC 43-05-01-13)

The emergency and remedial response plan (ERRP) is required to address those events that occur during the geologic storage of the CO_2 that have the potential to move injection fluid or formation fluid in a manner that may endanger a USDW during the operation or postinjection site care periods. Other emergency events may also include 1) CO_2 leakage to the atmosphere and 2) CO_2 migration outside of the storage reservoir permitted facility area, including migration into other nonpermitted formations, i.e., thief zones.

The ERRP describes the actions that the storage operator will take to address emergency events. If there is evidence that the injected CO_2 and/or associated pressure front may cause endangerment to a USDW, the storage operator is required to implement the following response protocol:

Cease injection activities.

1. Take all steps reasonably necessary to identify and characterize any pressure buildup and/or subsurface fluid movement.
2. Notify the NDIC DMR UIC Program Director of the emergency event within 24 hours.
3. Execute detailed response plans as presented in the applicable portions of the ERRP.

Regarding the cessation of CO_2 injection, discussions with the NDIC DMR UIC Program Director are necessary to determine if a gradual or temporary cessation of injection (using a set of preestablished parameters) may be appropriate. In addition, it is recommended that a set of emergency contacts (both internal and external) be developed and maintained during the life of the geologic storage project (see Section 3.4.1.5 Emergency Communications Plan).

Given that it is not possible to predict the specific nature of an emergency event or when it will occur, the ERRP is required to provide a framework that can be used to identify and classify an incident, develop a set of specific emergency response actions, describe the available emergency personnel and equipment, and develop an emergency communications plan. In addition, a process for reviewing and, if necessary, updating the ERRP over the lifetime of the project is required. These elements of the framework are briefly described below.

3.4.1.1 Identification of Local Resources and Infrastructure

The storage operator is required to identify the local resources and infrastructure near the geologic storage project that may be impacted by an emergency event. Local resources may include municipal USDWs, potable groundwater wells, lakes, or other surface water bodies; infrastructure might include wellheads, local or interstate roads, railroad tracks, or structures of nearby towns or cities. A map of the local area that provides the locations of these key resources and infrastructure, where relevant, will be included in this section of the plan.

3.4.1.2 Identification and Classification of Potential Emergency Events

For the purposes of this plan, an "emergency event" is an event that poses either 1) an immediate (or acute) risk to human health, resources, or infrastructure or 2) a potential (or chronic) risk to these same receptors should conditions worsen or no mitigative/remedial emergency responses be taken. On the other hand, events that do not pose either an acute or chronic risk to human health, resources, or infrastructure do not warrant emergency responses and are designated as "incidents." Essentially, the primary defining factor of an emergency event is whether the event has an immediate or imminent potential to result in an acute or chronic risk rather than simply having the potential to produce such a risk at some time in the future.

A site-specific, screening-level risk assessment or some other technical evaluation of the geologic storage project is a useful tool for identifying the technical risk categories that could lead to an emergency event. Based on previous risk assessments performed on other geologic storage projects, a common list of events or circumstances that have the potential to require an emergency response for the protection of USDWs and which provide an initial foundation for an ERRP at any CO_2 storage site, is provided below:

- Injection or monitoring well integrity failure.
- Injection well monitoring equipment failure (e.g., inoperable shutoff valve, inoperable temperature or pressure gauge, etc.).
- Failure of storage reservoir cap rock.
- Presence of unknown faults or fractures.
- Presence of undocumented, leaking (legacy) wells within the AOR.
- Induced seismic event occurs which results in new faults or fractures, the activation of existing faults or fractures, damage to legacy wells, or other outcomes which lead to the migration of fluids (CO_2 or formation brine) beyond the storage reservoir.

In addition to these project/operational events, the occurrence of a natural disaster (e.g., earthquake, tornado, lightning strike, etc.) also represents an event that may warrant emergency response planning as part of the ERRP.

The above list of events should be periodically reviewed and, if necessary, modified (i.e., emergency events are either added, deleted, or both) to reflect site-specific considerations. This modified list of potential “emergency events” can be used as the basis for the development ERRP.

3.4.1.3 Emergency Response Actions

For each of the emergency events identified above, the ERRP is required to contain an emergency response action. The emergency responses should build upon the response protocol presented earlier in Section 3.4.1. In all cases, the goal of the initial steps of the response protocol is to stop the emergency event and notify the emergency contacts as soon as possible. This should be followed by a more in-depth technical assessment that leads to the design and implementation of a remedial action plan, all of which should be done in consultation with the NDIC DMR UIC Program Director. An example of this approach is presented here for the vertical movement of brine or CO_2 into a USDW. This event could be caused by one of several failures, including failure of the confining zone, loss of mechanical integrity of the injection or monitoring well, or if the brine or CO_2 plume encounters an unknown fault, fracture, or well in the AOR. The immediate and primary responses to injection-related fluid migration into any USDW or surface water are cessation of CO_2 injection, notification of the emergency contact list, identification and location of the source of the release, and implementation of corrective action to stop the release. The location, size of the release, and access will control the course of the remedial action. In the event of an impact on water quality within a surficial aquifer system that directly affects water-supply wells, point of use, withdrawal water treatment, or alternate water-supply remedies would be implemented as an appropriate remedial response. Table 3-4 provides a summary of the basic actions required to respond to a detected “event.”

3.4.1.5 Emergency Communications Plan

In the event of an emergency, it is necessary for the storage operator to have available a communications plan which, depending upon the emergency event, will define both internal and external contacts to secure immediate assistance. Information, such as the following, may be provided to each of the contacts:

- Facility name, address, location, and telephone number
- Name of person reporting the incident
- Date and time of incident
- Nature of the incident, e.g., material released, etc.
- Extent of the incident, e.g., source and quantity of material released
- Media impacted by release (air, soil, and groundwater).
- Identify specific contractors and equipment vendors capable of providing necessary services and equipment to respond to such leaks or loss of containment.

In the event of an emergency requiring outside assistance, it is also important that the storage operator have a plan for managing communications with the public.

3.4.1.6 ERRP Reviews and Updates

The content of the ERRP includes items such as a schedule for reviewing and updating the ERRP on an annual basis. Examples of possible review schedules are suggested in the state regulations and include:

- At least once every 5 years following its approval by the permitting agency.
- Within 1 year of an AOR reevaluation.

Table 3-4. Illustrative Example of Permit Information Requirements: Response to Potential Emergency Event*

Item	Description/Comments
Immediately investigate and identify events that may result in a shutdown (downhole or at the surface).	The procedure that will be used to identify the cause of a shutdown should be described, considering the following potential events: 1. Injection or monitoring (verification) well integrity failure. 2. Injection well monitoring equipment failure (e.g., shutoff valve or pressure gauge, etc.). 3. A natural disaster (e.g., earthquake, tornado, lightning strike). 4. Fluid (e.g., brine) leakage to a USDW. 5. CO_2 leakage to USDW or land surface. 6. Induced seismic event.
Determine the severity of an event, categorizing it either as an "emergency" or an incident.	A procedure for categorizing an event as either an emergency or incident should be provided.
Define actions that will be implemented should an event be classified as an incident.	If an event is classified as an incident, the following actions should be taken: 1. Ensure all personnel are accounted for and that the storage facility is secure. 2. Determine cause of incident and use findings in operator training and to implement procedures as necessary to prevent reoccurrence. 3. Resume plant operations and injection.
Define actions that will be implemented should an event be classified as an emergency.	If the event is classified as an emergency and/or the injection well appears to lack mechanical integrity or if required monitoring indicates the well may lack mechanical integrity, the following actions should be taken: 1. Immediately cease injection. 2. Take all steps necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone. 3. Notify NDIC within 24 hours. 4. Perform a root cause analysis to determine cause of emergency or incident and use findings in operator training and to implement procedures as necessary to prevent reoccurrence before resuming injection. 5. Before resuming injection, operator will restore and demonstrate mechanical integrity to the satisfaction of the NDIC. 6. Notify the NDIC when injection can be expected to resume.

* This information is required if a shutdown (downhole or at the surface) is required.

- Within a prescribed period (to be determined in coordination with the permitting agency) following any significant changes to the injection process, the injection facility, or an emergency event.

- As required by the permitting agency.

If the review indicates that no amendments to the ERRP are necessary, the storage operator is required to provide the permitting agency with the documentation supporting the "no amendment necessary" determination. If the review indicates that amendments to the ERRP are necessary, it is required that these amendments be made by the storage operator and be submitted to the permitting agency within a specified period, e.g., 3 months, following their identification.

3.4.2 Financial Assurance Demonstration Plan (NDAC 43-05-01-09.1)

A financial assurance demonstration plan (FADP) is required and must be a qualifying financial responsibility instrument: surety or cash bond, trust fund, letter of credit, insurance policy, self-insurance, escrow account, or any other instrument NDIC finds satisfactory. A qualifying financial responsibility instrument must be sufficient to cover the cost of any corrective action that may be required at the geologic storage facility during any of its phases of operation, well plugging, postinjection site care and facility closure, emergency and remedial response, and endangerment to USDWs. A potential list of activities, which require coverage by the FADP and for which cost estimates are required, is presented in Table 3-5.

Table 3-5. Illustrative Example of Cost Estimates for Financial Assurance Demonstration (values[3] are provided for illustrative purposes only and require replacement)

Activity	Total Cost, $ millions
Performing Corrective Action on Wells in AOR	0.62
Plugging Injection Wells	2.70
Postinjection Site Care	18.3
Site Closure	3.40
Emergency and Remedial Response Actions	26.7
Endangerment of USDWs	6.44

The FADP is required to demonstrate that the financial instrument meets the criteria that are specified in the regulations regarding the level of coverage, protection of coverage, maintenance of the qualifying financial responsibility through project completion, and notifications of changes in conditions (e.g., adverse company financial conditions, changes in the funds required for performing required corrective actions, etc.) that require changes to the financial instrument (refer to NDAC 43-05-01-09.1).

There are specific requirements for using multiple qualifying financial responsibility instruments for specific phases of CO_2 storage project outlined in NDAC 43-05-01-9.1 §1f.

[3] U.S. Environmental Protection Agency, 2013, Underground injection control permit applications for FutureGen 2.0 Morgan County Class VI UIC Wells 1, 2, 3, and 4: FutureGen Industrial Alliance, Inc., U.S. Environmental Protection Agency, Region 5.

3.4.3 Worker Safety Plan (NDAC 43-05-01-05 §1e; NDAC 43-05-01-13)

The required worker safety plan includes discussions on topics such as the following:

a. Carbon dioxide safety training.

b. Safe working procedures at the storage facility wellsite.

c. A training schedule for worker safety training including scheduled refresher courses and worker inspection procedures to ensure a safe working conditions (i.e., What should the worker do every time when entering the surface location?).

The storage operator is required to state that a fully compliant Worker Safety Program that meets all state and federal requirements for worker safety protections, including Occupational Safety and Health Administration (OHSA) and NFPA (National Fire Protection Association), will be maintained and implemented.

More specifically, information provided in the Worker Safety Plan includes the following statements: 1) that all operations employees will receive training related to health and safety, operational procedures, and emergency response according to the roles and the responsibilities of their work assignments; 2) initial training will be conducted by, or under the supervision of, a project operations manager or a designated representative; and 3) trainers will be thoroughly familiar with the operations plan and the ERRP.

Included in the CO_2 safety training program are items such as annual training that teaches personnel to identify the dangers of CO_2, requirements for all employees and visitors to wear the proper personal protective equipment (PPE), and instructions for the performance of duties in ways that prevent the discharge of CO_2. The training could also include familiarization with operating procedures, and equipment configurations appropriate to the job assignment, as well as emergency response procedures equipment, and instrumentation. New personnel will be instructed before beginning their work. A contractor and visitor orientation to address and document CO_2 safety awareness to ensure all persons on-site are trained and aware of the dangers of CO_2 may also be considered.

The CO_2 safety training plan could also include information and frequency of refresher training for all appropriate operations personnel. This may include monthly briefings to operations personnel according to their respective responsibilities to highlight recent operating incidents, actual experience in operating equipment, and recent storage reservoir monitoring information.

Lastly, the storage operator plan needs to include a method to document and record worker safety training, at a minimum with the person's name, date of training, type of training (e.g., initial or refresher), and the instructor's name documented.

3.4.4 Testing and Monitoring Plan

The SFP requirements of the NDAC include several detection and monitoring plans. These include the following:

- Corrosion monitoring plan (NDAC 43-05-01-05 §1f; NDAC 43-05-01-15).

- Leak detection and monitoring plan for all wells and surface facilities (NDAC 43-05-01-05 §1g; NDAC 43-05-01-14).

- Leak detection and monitoring plan to monitor any movement of the CO_2 outside of the storage reservoir (NDAC 43-05-01-05 §1h).

- Testing and monitoring plan (NDAC 43-05-01-05 §1l; NDAC 43-05-01-11.4).

Because the testing and monitoring plan incorporates the elements of all the other three detection and monitoring plans: 1) Monitoring and Prevention Plan, 2) Surface Leak Detection and Monitoring Plan, 3) Subsurface Leak Detection and Monitoring Program, this section of the SFP integrates these requirements into a single plan, which comprises the following:

- Written descriptions which describe in detail the testing and monitoring for the preinjection baseline, operational, and postinjection site care and facility closure phases of the project.

- Maps which show the location of the sample points and the types of samples that will be taken.

- Tables which will describe the type of samples, number of samples, and duration of sampling for each of the phases of the project.

3.4.4.1 Analysis of Injected CO_2

The storage operator is required to specify an appropriate analytical method to analyze the chemical and physical characteristics of the injected CO_2. An example of the types of chemical composition data of interest is shown in Table 3-6; physical characteristics of interest include density and viscosity.

All analytical methods used to generate these data should be consistent with standard analytical methods and techniques that are generally accepted by industry, and all testing should be performed and documented with enough frequency to yield representative characterization data of the CO_2 stream to be injected and stored.

Table 3-6. Illustrative Example of Chemical Components Targeted for Characterization in the Injected Carbon Dioxide Stream (values[4] are provided for illustrative purposes only and require replacement)

Component*	Measurement, vol%**
Carbon Dioxide	95
Ethane	<0.1
Propane	<0.1
n-Butane	<0.1
Hydrogen	<0.1
Nitrogen	4
Methane	<1
Oxygen	<0.001
Water, ppm	500

* Not all components may be present, illustrative only.
** Unless otherwise indicated.

3.4.4.2 Leak Detection and Monitoring Plan: Wells and Surface Facilities

The testing and monitoring plan is required to include a leak detection and monitoring program for all wells and surface facilities as per NDAC 43-05-01-14. The plan is required to 1) identify the potential pathways for the release of CO_2 to the atmosphere, 2) identify potential pathways for the degradation of groundwater resources with a particular emphasis on USDW, and 3) identify potential pathways for the migration of CO_2 into any mineral zone within the facility area. Leak detection/monitoring efforts are required for the wellheads of all injection and subsurface observation wells, other surface components of the CO_2 injection system (e.g., flange connections, valves, etc.), and the CO_2 transport pipeline. Specifically, the plan describes the type of leak detection systems that will be used along with the location and inspection/testing schedule for each system. A written description, system diagrams and workflows, and a table of the system specifications should also be provided for each system. Where applicable, leak detectors must be integrated with automated warning systems and must be inspected and tested on a semiannual basis. If defective, the leak detectors must be repaired or replaced within 10 days. If necessary, the Commission may require that each repaired or replaced detector be retested. An extension of time for repair or replacement of a leak detector may be granted upon a showing of good cause by the storage operator. A record of each inspection must include the inspection results, must be maintained by the operator for at least 10 years, and must be made available to the Commission upon request. Refer to NDAC 43-05-01-14.

The storage operator is required to immediately report to the Commission 1) any leak detected at any well or surface facility; 2) any pressure changes or other monitoring data from subsurface observation wells that indicate the presence of leaks in the storage reservoir; and 3) any other indication that the storage facility is not containing CO_2, whether the lack of containment concerns the storage reservoir, surface equipment, or any other aspect of the storage facility.

[4] National Energy Technology Laboratory, 2019, Quality guidelines for energy system studies: CO_2 impurity design parameters: U.S. Department of Energy, Systems Engineering & Analysis Directorate, NETL-PUB-22529. DOI: 10.2172/1566771, www.netl.doe.gov/projects/files/QGESSCO2ImpurityDesignParameters_010119.pdf (accessed 2020).

3.4.4.3 *Leak Detection and Monitoring Plan: Movement of the CO_2 Outside of the Storage Reservoir*

The storage operator is required to put in place a leak detection and monitoring plan that will be capable of verifying that the geologic storage project is operating as permitted; i.e., it is not endangering USDWs or resulting in the movement of CO_2 outside of the defined storage reservoir. This plan is often referred to as the monitoring, verification, and accounting (MVA) program. Similar to the leak detection and monitoring plan for the wells and surface facilities, this plan is also required to 1) identify the potential for the release of CO_2 to the atmosphere and 2) identify potential for the migration of CO_2 into any mineral zone within the facility area. See NDAC 43-05-01-05 §1h.

This plan typically includes the collection and characterization of samples taken from the surface, near surface, and subsurface environments of the storage reservoir. These samples should be collected during the preinjection, operational, and postinjection/closure phases of the storage project. Emphasis should be on the collection of data within the facility area, the CO_2 storage reservoir, and within 1 mile (1.61 kilometers) of the outside boundary of the facility area. All sampling analysis (e.g., groundwater well sample) filed with NDIC must be from a state-certified laboratory. See NDAC 43-05-01-11.4, NDAC 43-05-01-14.

3.4.4.3.1 Near-Surface Monitoring

Before injection begins, near-surface environmental monitoring establishes a baseline for naturally occurring levels of CO_2 in the surface and shallow subsurface environment. The purpose of this baseline is to provide a basis for comparing near-surface conditions before and after the injection of CO_2 is initiated. Following the collection of a baseline, continued monitoring during operational and postoperational phases should be continued, considering a reduced sampling frequency over time if the monitoring shows consistent levels of CO_2 when compared to the established baseline. All water sampling analyses (e.g., groundwater well sample) filed with NDIC must be from a state-certified laboratory. The state does not certify air gas samples. A qualified third-party laboratory should be used at the discretion of the operator. An example of how a near-surface environmental monitoring could be accomplished is discussed below:

- Soil gas monitoring can be deployed to assess the potential risks to USDW by determining the potential vertical movement of CO_2 from the storage reservoir through the soils within the AOR. Preinjection baseline data, if available, could be used to define the spatial distribution for the monitoring locations and set the frequency of the soil gas monitoring. The proposed monitoring program that is implemented will be project-specific and be focused on the identified risks to site-specific USDWs.

- A groundwater monitoring program can be designed to address potential risks of groundwater contamination by CO_2 or brine within the AOR. Baseline and periodic monitoring of groundwater quality and geochemical changes above the confining zone, or cap rock, are required as a means of assessing the movement of CO_2 through the confining zone in the subsurface. This monitoring will be accomplished by sampling fluids from freshwater wells or monitoring wells. The location and number of these wells are based on project-specific USDW risk factors such as the CO_2 injection rate and volume, the geology, the presence of artificial penetrations such as abandoned oil and gas wells, and the baseline geochemical data. Any modeling that results in updates of the AOR evaluation would need to be addressed as part of the monitoring program design. These same factors will also dictate the frequency of monitoring that is required for the monitoring plan to be effective.

- Surface water monitoring within the AOR is not specifically required by the regulations. However, the storage operator could consider such monitoring to complement the near-surface monitoring that is required by the regulations (see above) to provide another line of evidence for determining if the vertical migration of CO_2 and/or formation brines is occurring or has occurred. Surface water monitoring would require the acquisition of baseline samples from lakes, ponds, and various sites along perennial streams overlying the delineated subsurface CO_2 plume. This effort would establish a baseline for the presence of dissolved CO_2, methane, and other gases that may be present in surface waters. These same factors will inform the frequency of monitoring to provide an effective monitoring program throughout the duration of the storage operations.

The gathering and reporting of surface air quality monitoring data are required from sites designated during the operations phase (NDAC 43-05-01-11.4). The storage operator should also consider incorporating surface air quality monitoring into the PISC (postinjection site closure) plan. This may be best accomplished by sampling the ambient air at select soil gas monitoring station(s). This sampling and reporting effort would need to be coordinated with the capture plant air quality sampling program. It is important to note that the detection of CO_2 in the surface and near-surface environment alone is not sufficient to make the determination that CO_2 is escaping from the storage reservoir. Such a determination requires an established baseline with samples and data that account for normal seasonal fluctuations as well as in-depth quality assurance checks on sampling, handling, and analysis combined with retesting if anomalous or unexpected results are reported. For this reason, the gathering of baseline data in surface air and other environmental media before starting CO_2 injection is critical since it has been established at other sites that there may be natural, biological sources of CO_2 that are responsible for such observations. Ultimately, the goal of every sampling effort is to support a risk-based analysis that is focused on the protection of USDW.

3.4.4.3.2 Subsurface Monitoring (NDAC 43-05-01-05 §1h and §g2)

The goal of subsurface monitoring is to track the vertical and lateral movement of both the subsurface CO_2 plume and pressure front in the storage reservoir and AOR. A number of both direct methods and indirect methods can be deployed for this purpose as part of this testing and monitoring program as summarized in Table 3-7 and briefly discussed below:

- Injection zone testing. The storage operator is required to characterize in situ fluids (waters) within the facility area and within 1 mile (1.61 kilometers) of the outside boundary. See NDAC 43-05-01-05. Specific injection zone methods are typically detailed in the APD.

Table 3-7. Permit Information Requirements: Plume Monitoring

Item	Description/Comments
Monitor injection pressure; the rate, volume or mass, and temperature of the injected CO_2; and the pressure of the annulus between the tubing and the long-string casing and the annulus fluid volume.	Describe the proposed use of continuing recording devices for the monitoring of the required parameters.
Provide protections that are designed to alert the operator, and shut in the well when operating parameters diverge beyond permitted ranges or gradients which should be specified in the permit.	• Define acceptable ranges for key operating parameters. • Provide alarms and automatic surface shutoff systems or, at the discretion of NDIC, downhole shutoff systems or other mechanical devices that provide the required protections should operating parameters exceed acceptable ranges.
All Direct and Indirect, Surface and Subsurface Monitoring Methods	
4. List of each method and purpose/explanation 5. Location/placement 6. Frequency of measurement 7. Calibration of instrument(s) 8. Maintenance/testing/repair/replacement 9. Data reporting schedule	• The monitoring methods that are proposed for monitoring the CO_2 plume should be described in detail, including both direct and indirect, surface and subsurface monitoring methods. • A schedule for the reporting of the monitoring data should also be provided.

- Indirect methods of testing – geophysical. The storage operator is required to track the extent of the CO_2 plume using a combination of geophysical techniques, such as seismic, electrical, gravity, interferometric synthetic aperture radar (InSAR) or electromagnetic surveys, and downhole carbon dioxide detection tools. See NDAC 43-05-01-11.4.

- Indirect methods of testing – downhole monitoring of injection and/or monitoring wells. The storage operator may track the extent of the CO_2 plume using several monitoring techniques such as wireline logging downhole formation attributes, CBLs, downhole temperature and pressure gauges, and fiber optic distributed temperature systems. In addition, process monitoring data that are collected at an injection well including injection rates and volume, surface injection pressures and temperature, and tubing-casing annulus pressure can provide valuable information regarding the potential movement of CO_2. See NDAC 43-05-01-05. The APD provides details on these indirect methods.

3.4.4.4 Injection Well Mechanical Integrity Demonstration – Testing and Monitoring Plan (NDAC 43-05-01-11.1, 43-05-01-11.2, 43-05-01-11.3, and 43-05-01-11.4)

The storage operator is required to demonstrate internal and external mechanical integrity of the injection well prior to injection and during operations until the well is plugged. The testing and monitoring plan should include an initial mechanical integrity test (MIT) demonstration prior to injection, both internally and externally, and include a schedule for periodic integrity tests during the operational and postoperational phases of the project. In addition, the testing and monitoring plan should address continuous monitoring requirements to demonstrate well integrity during injection operations (e.g., tubing-casing annulus pressure gauge). More details regarding each of these demonstrations are provided below:

- The internal MIT is considered common practice in the UIC program. This integrity demonstration typically consists of a 15-minute pressure test at approximately 1000 psi. NDIC requires notification and a representative of the Commission to be on-site to witness and approve the MIT. The MIT demonstration is required prior to injection and at least every 5 years, unless otherwise prescribed by the NDIC, once operations begin and until the well is plugged.

- The external mechanical integrity demonstration requirement poses additional challenges such as the cost of logging and wellbore configuration (i.e., permanent packer versus retrievable packer). The external mechanical integrity demonstration is required prior to injection and annually thereafter once operations begin and until the well is plugged. The regulations, which originate from the federal Class VI rule and have been adopted by North Dakota as part of Class VI primacy, the methods for external mechanical integrity demonstration testing to the following options: 1) an oxygen activation log, 2) a temperature log, or 3) a noise log.

External Mechanical Integrity Demonstration: It is recommended that the storage operator, in collaboration with NDIC, develop a cost-effective approach to perform external mechanical integrity. The method of the test will be determined by the well configuration. An ideal test method would allow for the log to be run through the tubing to reduce the interruption in injection operations. Alternatively, it may be both costly and operationally challenging to pull the tubing and retrieve the packer every year to conduct the external MIT. Other technologies may offer a more cost-effective solution to the annual external integrity demonstration (e.g., external fiber optic cable).The ultrasonic CBL is the NDIC-preferred method for the initial external mechanical integrity demonstration, while also demonstrating compliance with well casing and cementing requirements. The temperature log can be run through tubing and would be an acceptable method of external mechanical integrity demonstration during the operational phase of a CO_2 storage project.

3.4.4.5 Documentation of Testing and Monitoring Data/Information (NDAC 43-05-01-18)

It is important to be aware of the reporting requirements when performing testing and sampling for the SFP application. The storage operator is required to document the testing and monitoring results by preparing records that include the following:

- The date, exact place, and time of sampling or measurements
- The individual who performed the sampling or measurements
- The date analyses were performed
- The individual who performed the analyses
- The analytical techniques or methods used
- The results of such analyses

3.4.5 Plugging Plan (NDAC 43-05-01-11.5)

The storage operator is required to prepare, maintain, and comply with an injection well plugging plan that is acceptable to the Commission (see NDAC 43-05-01-11.5 for the specific requirements).

Figure 3-1 presents a generic wellbore schematic for an injection well (i.e., the wellbore configuration prior to plugging and abandonment), and Figure 3-2 presents an example of a plugged injection wellbore (i.e., the proposed configuration of the well following the plugging and abandonment procedure), which depicts the wellbore in Figure 3-1 following completion of the plugging process. Figure 3-2 provides information regarding the depth of cement plugs that will be placed in the well as part of the plugging process as well as the location of the cement retainer, the squeezed cement at the perforation intervals, and the cement placed at the bottom of the well. As was the case in Figure 3-1, the types of cement that are proposed for use are identified in Figure 3-2.

Figures of this type, accompanied by a detailed, step-by-step, plugging and abandonment procedure that will yield the plugged well shown in Figure 3-2, provide the necessary information in the permit application to meet the requirements (see NDAC 43-05-01-11.5 for the detailed plugging and abandonment requirements).

3.4.6 PostInjection Site and Facility Closure Plan (NDAC 43-05-01-19)

This PISC and facility closure plan describes the activities the storage operator will perform to meet the requirements of NDAC 43-05-01-19. During the postinjection phase, the storage operator is required to monitor groundwater quality, surface air quality, and track the position of the carbon dioxide plume and pressure front for a minimum of 10 years' postinjection. Prior to receiving certification for project completion (i.e., transfer of title) issued by NDIC, the storage operator will plug all wells not specifically transferred to the state as per NDAC 43-05-01-11.5, reclaim the site to its original condition, and submit a final assessment report and any other associated documentation to demonstrate that the CO_2 is contained within the storage facility (see NDAC 43-05-01-19 §9).

3.5 Injection Well and Storage Operations (NDAC 43-05-01-05 [SFP] and NDAC 43-05-01-11.3 [Injection Well Operating Requirements])

The injection well and storage operations' section of the SFP addresses the engineering criteria for operating the injection well in a manner that protects USDWs. The information that is required to comply with the permit requirements for injection well and storage operations is presented in Table 3-8.

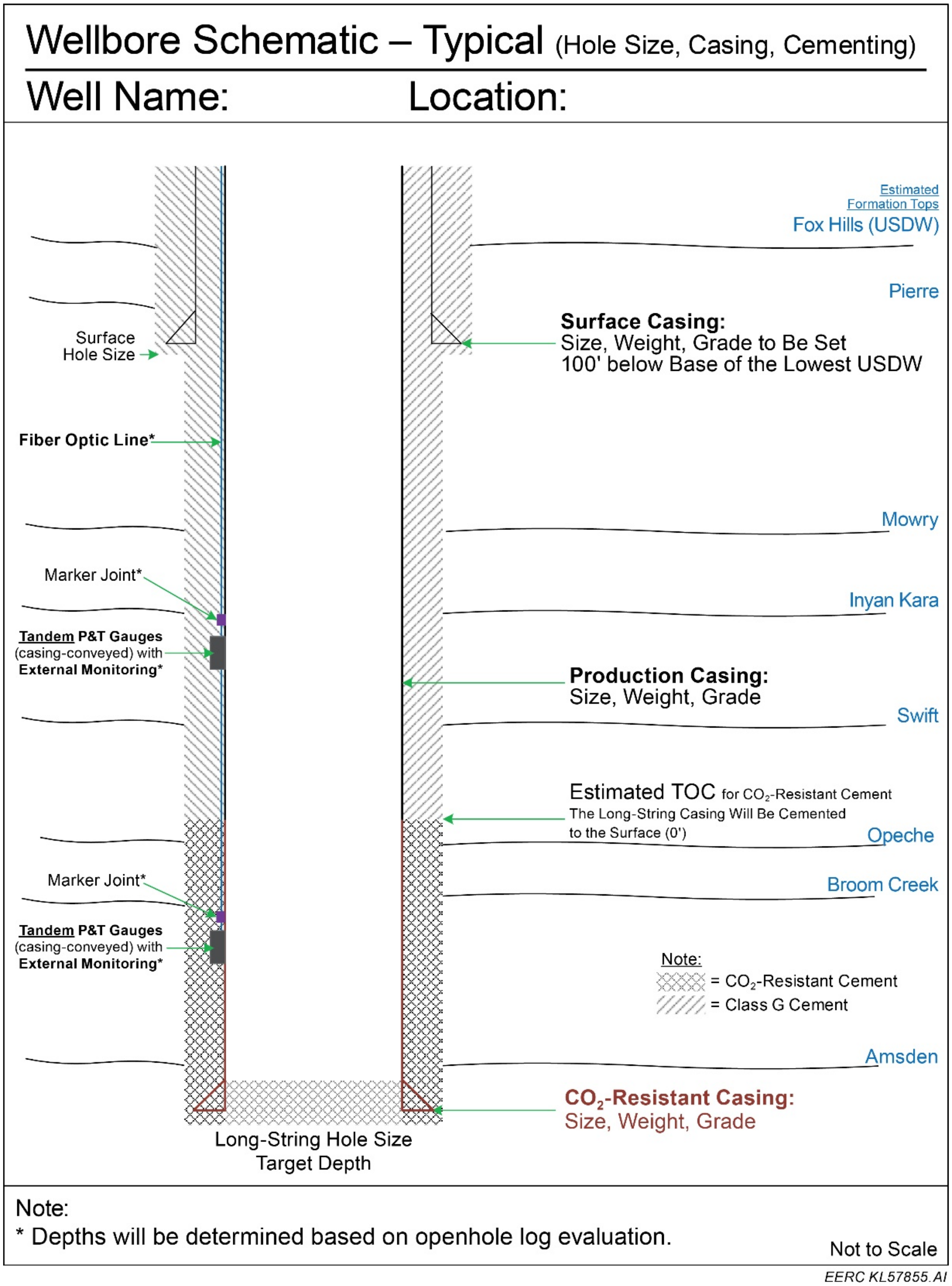


Figure 3-1.Example of injection wellbore schematic.

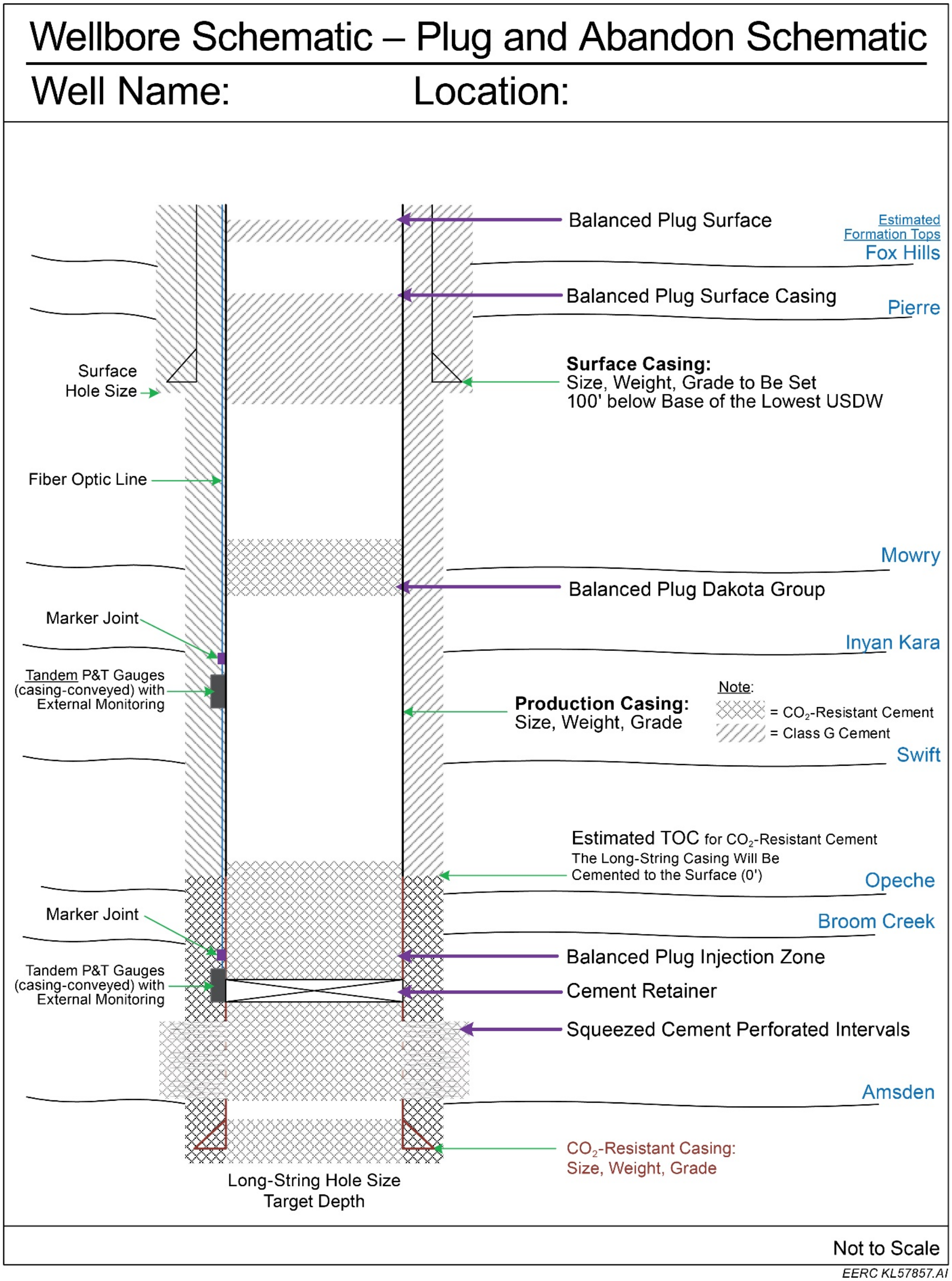


Figure 3-2. Example of plugged injection wellbore.

Table 3-8. Permit Information Requirements: Storage Operations (preoperational characterization of the injection and confining zones)

Item	Description/Comments
Injected Volume	
Total Injected Volume	The proposed total volume of injected CO_2 that was used in the modeling and dynamic simulations of the CO_2 injection should be provided.
Injection Rates	
Injection Well Name and Location Proposed Average Injection Rate Proposed Maximum Daily Injection Rate	The name and location of each injection well should be provided along with the proposed average and maximum daily injection rates that are part of the design basis for the project and that were used during modeling and simulation studies.
Pressures	
Formation Fracture Pressure	The predicted formation fracture pressure that is calculated from the modeling and simulation studies should be provided.
Surface Injection Pressure	• The proposed maximum allowable surface injection pressure should be provided based on the modeling and simulation studies. • Except during stimulation, the storage facility operator shall ensure that the surface injection pressure does not exceed 90% of the fracture pressure of the injection zone to avoid the initiation of new fractures or propagation of existing fractures in the injection zone. The injection pressure must not initiate fractures in the confining zone or cause the movement of injection or formation fluids that endanger USDW.
Annulus Pressure	• The proposed annulus pressure should be provided based on the modeling and simulation studies. • The annulus between the tubing and the long string shall be filled and sealed with a noncorrosive fluid, approved by NDIC, with a pressure maintained that exceeds the operating injection pressure.
Bottomhole Pressure	The proposed average and maximum bottomhole pressures based on the modeling and simulation studies should be provided.

4.0 INJECTION WELL PERMIT (43-05-01-09 WELL PERMIT APPLICATION REQUIREMENTS)

The final regulatory approval necessary prior to beginning injection operations at a storage facility is the Application for Carbon Dioxide Storage (ACDS). This application is a request for approval to convert and operate the TAO well that was originally permitted as a stratigraphic test well and constructed to Class VI well construction requirements (see Section 2.0 Well Drilling Permit) as a CO_2 injection well. The well conversion application can be filed concurrently with the SFP application. While the SFP application needs to be approved prior to receiving approval of the well conversion, the filing of these applications together will ensure the most efficient regulatory review and approval process.

The well-specific data and information that are required in an application to convert the TAO well to a Class VI CO_2 storage injection well are presented in NDAC 43-05-01-09 (Well Permit Application Requirements). In this instance, the application is focused on obtaining a permit to convert and operate a previously drilled and constructed stratigraphic test well for the purpose of geologic CO_2 storage.

4.1 General Information

The request for approval to convert the stratigraphic well will be made using the ACDS, which will be provided by the NDIC. The general information required to complete the form consists of the name of storage facility, the operator name, address, and phone number. The storage operator is required to provide specific information on the injection well, such as well location, injection zone and confining zone formation tops and thicknesses, bottom hole fracture pressure, fracture gradient, maximum injection pressure and rate. The form also requires specific information on the well construction and final well configuration of the tubing and packer.

4.2 Required Attachments

The storage operator is required to provide application attachments as listed in NDAC 43-05-01-09 §2 and §3. The permit application attachments are an update of the data and information provided in the stratigraphic test well APD. For instance, the proposed plats and pad layout cut and fill diagram (Appendix A) are required to be updated to the as-built well location plat and the well site facility layout diagram, including the surface injection system and its appurtenances. A wellbore schematic is required to be filed with updated as-built well construction information and the proposed injection well configuration showing the location of the perforations, tubing and packer specifications, and tubing depth and packer setting depth (example provided in Figure 4-1). The geophysical logs and ultrasonic CBL from the drilling and logging of the well will be considered as part of the regulatory review of this application. A conversion procedure describing the steps necessary to complete the well as a CO_2 storage injection well is required, a simplified example of the procedure is provided in this section. Data and information on the CO_2 stream are required to be filed by the applicant as part of a signed affidavit specifying the chemical constituents, their relative proportions, physical properties, and the source of the carbon dioxide stream. In addition, the application includes information on the compatibility of the carbon dioxide stream with fluids in the injection zone and minerals in both the injection and the confining zone, based on the results of formation testing. Information on the compatibility of the CO_2 stream with the materials used to construct the well is required as part of the application to operate. It is recommended to review NDAC 43-05-01-09 §2 and §3 for a complete and detailed list of the required permit attachment items that are required to accompany the ACDS. A simplified example of a proposed conversion procedure and the injection well schematic (Figure 4-1) showing the proposed final well configuration are provided below:

1. Move-in and rig up (MIRU) workover rig.
2. Install blowout preventer (BOP).
3. Circulate to clean the wellbore.
4. MIRU wireline services.
5. Makeup and run in hole (RIH) perforation guns to perforate the injection zone. The perforation intervals are provided in this procedure.
6. RIH with retrievable packer and treating string.
7. Perform injectivity test.
8. Perform stimulation, if necessary. Stimulation program needs to be designed according to the injectivity test and formation solubility results. NDIC approval is required prior to performing well stimulation on the injection well (NDAC 43-05-01-11.3).
9. POOH retrievable packer and treating string.
10. RIH with CO2 resistant packer (provide packer setting depth) and CO_2 resistant injection tubing (provide tubing depth).
11. MIT pressure test packer and tubing-casing annulus. Contact NDIC to witness MIT 24 hours prior to MIT test. MIT well to 1,000 psi for 15 minutes or as directed by NDIC, charting pressure test. NDIC must witness MIT in accordance with state regulations. Well is ready for injection upon MIT approval from NDIC.
12. Nipple down BOP and nipple up wellhead.
13. Pressure test wellhead.
14. Rig down and move out workover rig.
15. The well is ready for installation of surface equipment to begin injection operations.

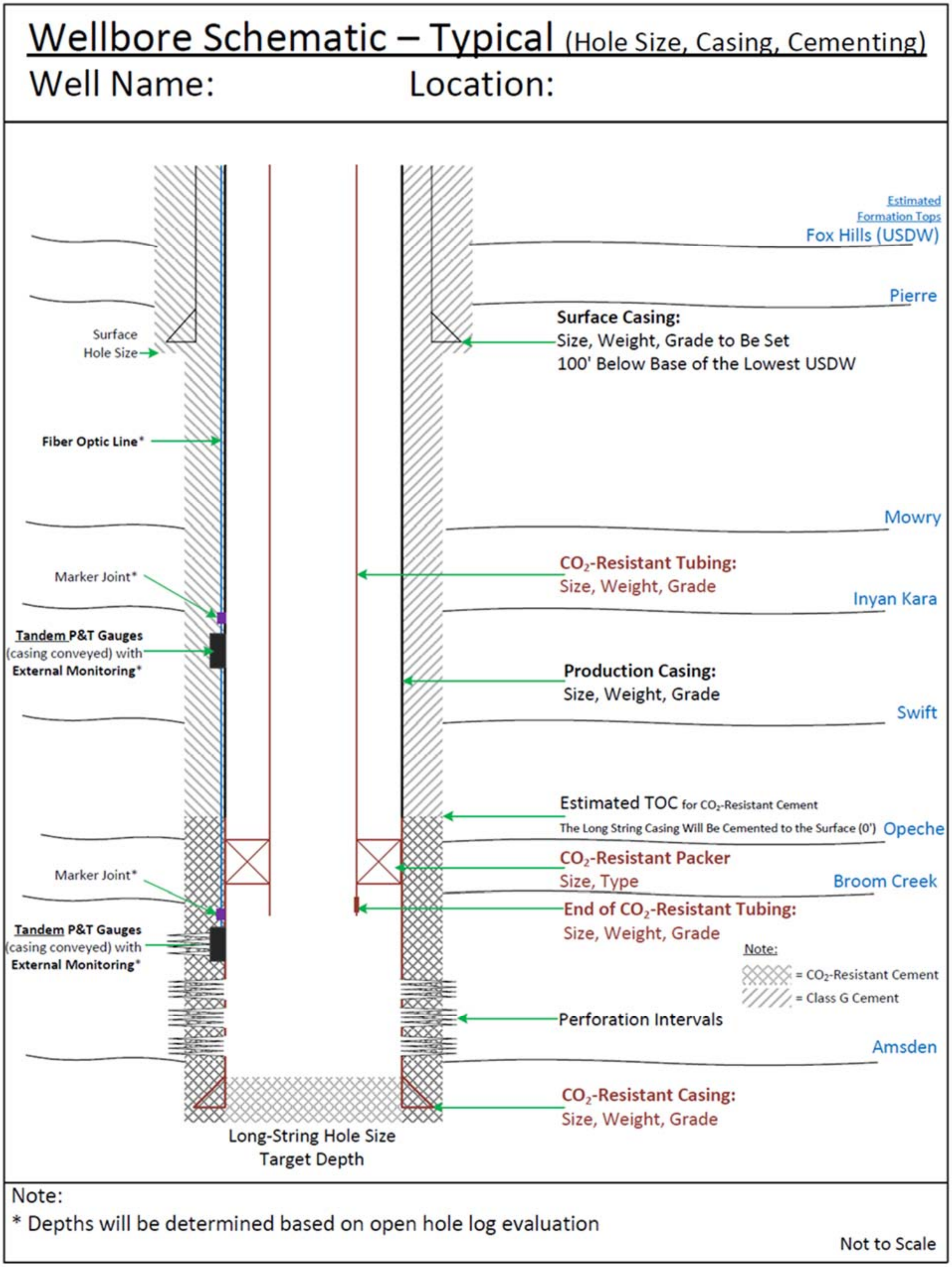


Figure 4-1. Example of final injection well configuration schematic.

As the applicant prepares the permit materials for submission, it is recommended to communicate with the NDIC regarding the commission's preferred method of receiving each application package (i.e., the SFP application and the ACDS). Approval of these applications complete the regulatory permitting process necessary to begin storage operations of the geologic CO_2 storage facility.

APPENDIX A

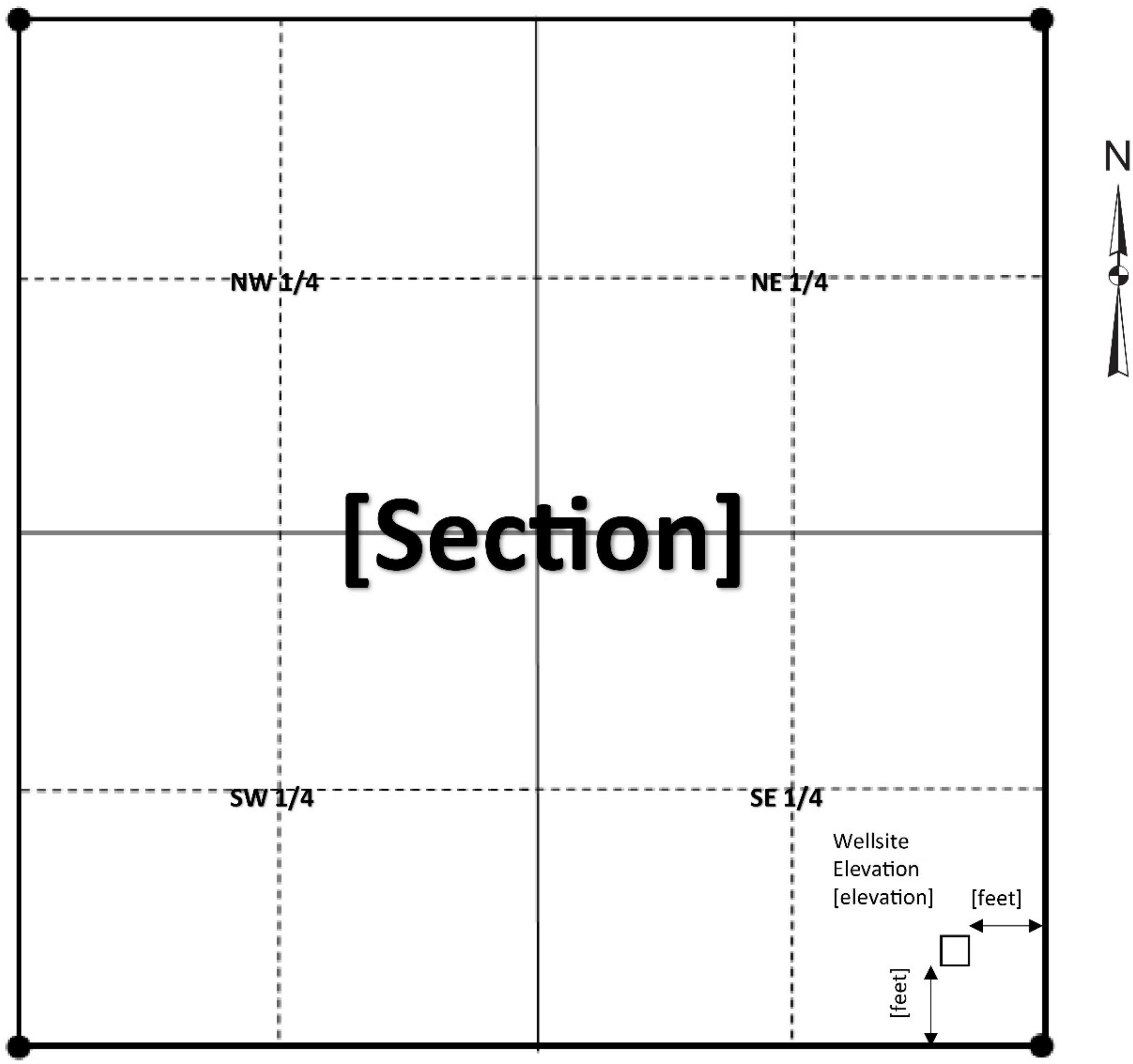
PLAT PACKAGE EXAMPLES

WELL LOCATION PLAT

[Company Name]
[Company Address]

[Well Name]

[distance] feet from the [N/S/E/W] line and [distance] feet from the [N/S/E/W] line (surface location)
Section [section] , T. [township] , R. [range]
[county] County, North Dakota
Surface owner @ Wellsite –[surface owner]
Latitude [latitude] , Longitude [longitude] (surface location)



Scale [in.=ft]

I hearby certify that this survey was prepared by me or under my direct supervision and that I am a duly Registered Land Surveyor under the laws of the state of North Dakota.

Surveyed By Date

Registered Land Surveyor in North Dakota stamp required

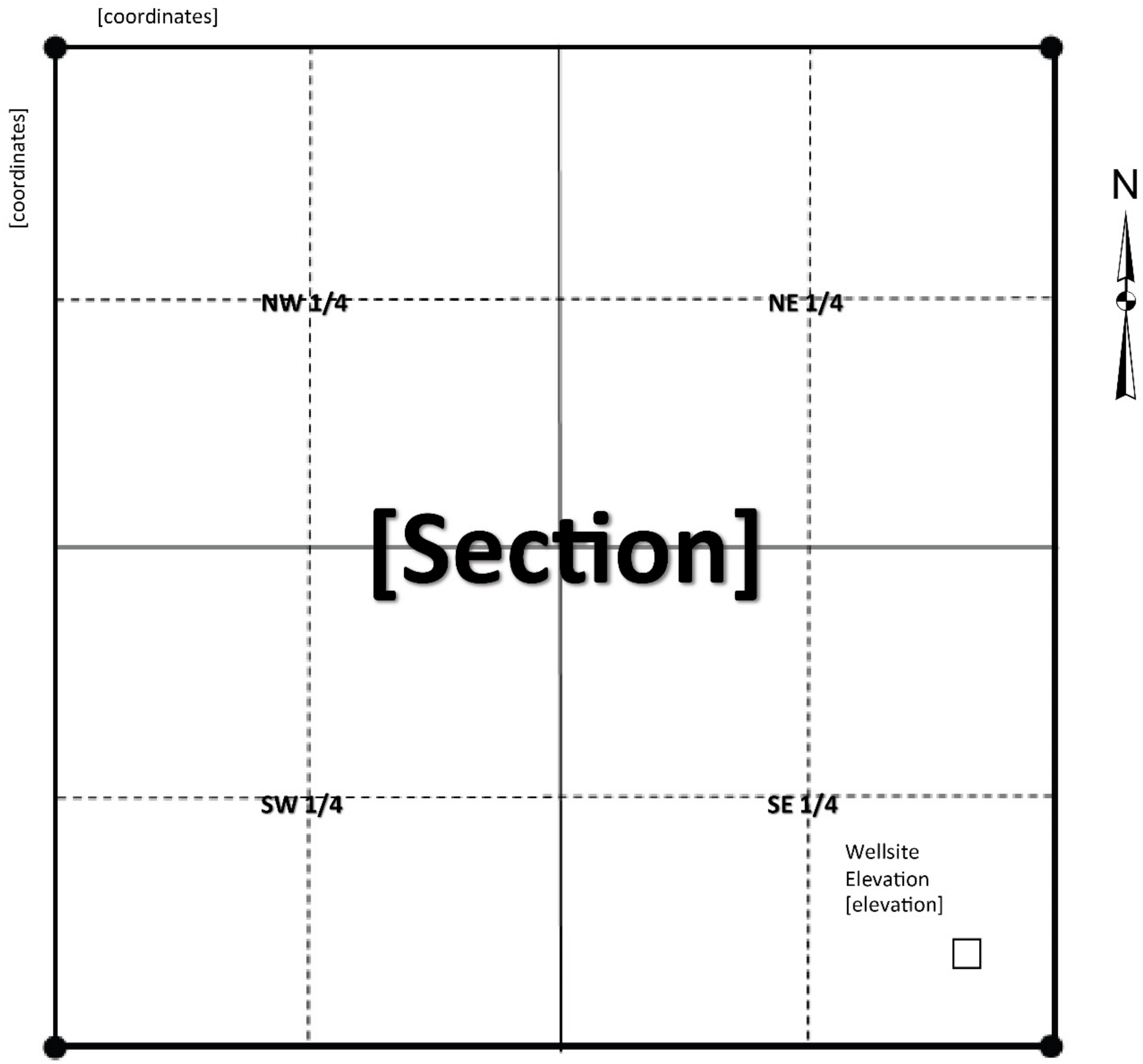
EERC KL57910.AI

HORIZONTAL SECTION PLAT

[Company Name]
[Company Address]

[Well Name]

[distance] feet from the [N/S/E/W] line and [distance] feet from the [N/S/E/W] line (surface location)
Section [section], T. [township], R. [range]
[county] County, North Dakota
Surface owner @ Wellsite – [surface owner]
Latitude [latitude], Longitude [longitude] (surface location)



Scale [in. = ft]

I hearby certify that this survey was prepared by me or under my direct supervision and that I am a duly Registered Land Surveyor under the laws of the state of North Dakota.

Surveyed By Date

Registered Land Surveyor in North Dakota stamp required

EERC KL57902.AI

[Company Name]
[Well Name]
Section [section] , T. [township] , R. [range]

Wellsite Elevation	[elevation] MSL
Well Pad Elevation	[elevation] MSL

Excavation	[value] C.Y.
Embankment	[value] C.Y.
Plus Shrinkage (+30%)	[value] C.Y.
	[value] C.Y.
Stockpile Topsoil (6”)	[value] C.Y.
Road Embankment & Stockpile from Pad	[value] C.Y.
Disturbed Area From Pad	[value] Acres

NOTE:
All cut end slopes are designed at 1:1 slopes &
All fill end slopes are designed at 1 1/2:1 slopes

Wellsite Location
[distance] FSL
[distance] FEL

Composed By:	Surveyed By:	Approved By:	Date:	Project Number:
[name]	[name]	[name]	[date]	[project number]

EERC KL57911.AI

[Well Name]
Pad Layout

(Topsoil Stockpile)

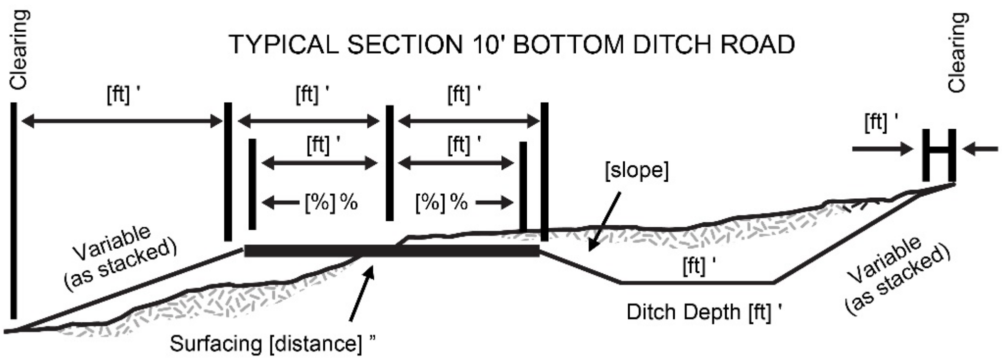
(Map)

Well Name	Elevation	Cut/Fill
[Well Name]	[elevation]	[cut/fill]

Composed By:	Surveyed By:	Approved By:	Date:	Project Number:
[name]	[name]	[name]	[date]	[project number]

EERC KL57905.AI

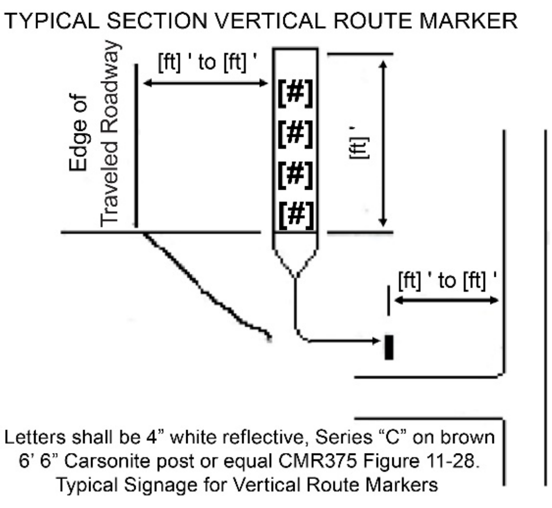
[Well Name]
Roadway Typical Sections



TYPICAL "B"

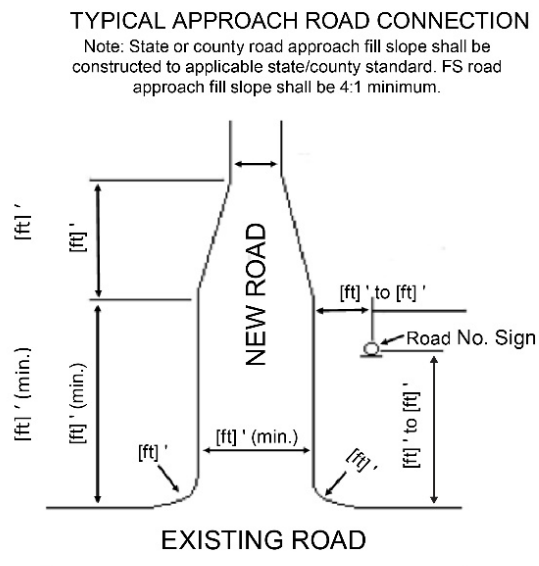
No Scale

FILL SLOPES	FILL WIDENING	CUT SLOPES
[fill slopes]	[fill widening]	[cut slopes]



Letters shall be 4" white reflective, Series "C" on brown 6' 6" Carsonite post or equal CMR375 Figure 11-28. Typical Signage for Vertical Route Markers

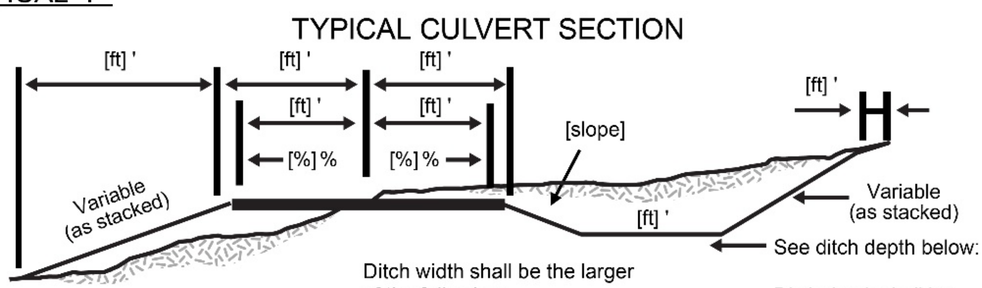
TYPICAL "F"



TYPICAL "E"

No Scale

* As Noted on Road Sheets



TYPICAL "A"

No Scale

Ditch width shall be the larger of the following:
A. Standard ditch width
B. 2 times the pipe diameter

Ditch depth shall be:

CMP Diameter	Ditch Depth
18"	2.5'
24"	3.0'
36"	4.0'
45"	5.0'

Computed and Drawn By:	Surveyed By:	Approved By:	Date:	Project Number:
[name]	[name]	[name]	[date]	[project number]

EERC KL57864A.AI

[Operator Name]
[Well Name]
[distance] FSL & [distance] FEL
[location] 1/4 [location] 1/4, Section [section]
T. [township] , R. [range]
[county] County, North Dakota

(County Access Route Map)

Requirements:

Figure must include topography; county; state and interstate highways; purposed route to wellsite with existing and purposed roads; railroads; towns; occupied buildings, etc.

Map "[A,B,C...] "
County Access Route

Legend

Existing Roads

Proposed Roads

EERC KL57906.AI

(Well Location Map)

Requirements:

- ID proximity to company-owned/leased surface
- ID proximity of proposed CO_2 injection well pad
- ID proximity of dry hole and producing wells
- ID occupied building/water supply pipelines, city limits, BLM lands, etc.

(EERC will prepare this)

EERC KL57907.AI

(Facility Map)

Facility map must provide the facility area, proposed injection well, proposed access roads, proposed well pad, facility property line, and city/town limits, railroads, highways, on a satellite image, etc.

(EERC will prepare this)

EERC KL57908.AI

APPENDIX B

CROSSWALK OF TEMPLATE SECTIONS AND CITATIONS FROM NDCC AND NDAC ON CO_2 STORAGE

Appendix B. Crosswalk of Template Sections and Citations from North Dakota Century Code (NDCC) Chapter 38-22 Carbon Dioxide Underground Storage and North Dakota Administrative Code (NDAC) Chapter 43-05-01 Geologic Storage of Carbon Dioxide

Template Section	NDCC/NDAC Reference(s)	Requirement
Pore Space Access	NDCC 38-22-06 §3 and §4 NDAC 43-05-01-08 §1 and §2	*NDCC 38-22-06* 3. Notice of the hearing must be given to each mineral lessee, mineral owner, and pore space owner within the storage reservoir and within one-half mile of the storage reservoir's boundaries. 4. Notice of the hearing must be given to each surface owner of land overlying the storage reservoir and within one-half mile of the reservoir's boundaries. *NDAC 43-05-01-08* 1. The commission shall hold a public hearing before issuing a storage facility permit. At least forty-five days prior to the hearing, the applicant shall give notice of the hearing to the following: a. Each operator of mineral extraction activities within the facility area and within one-half mile [.80 kilometer] of its outside boundary; b. Each mineral lessee of record within the facility area and within one-half mile [.80 kilometer] of its outside boundary; c. Each owner of record of the surface within the facility area and one-half mile [.80 kilometer] of its outside boundary; d. Each owner of record of minerals within the facility area and within one-half mile [.80 kilometer] of its outside boundary; e. Each owner and each lessee of record of the pore space within the storage reservoir and within one-half mile [.80 kilometer] of the reservoir's boundary; and f. Any other persons as required by the commission. 2. The notice given by the applicant must contain: a. A legal description of the land within the facility area. b. The date, time, and place that the commission will hold a hearing on the permit application. c. A statement that a copy of the permit application and draft permit may be obtained from the commission.

Continued . . .

Appendix B. Crosswalk of Template Sections and Citations from North Dakota Century Code (NDCC) Chapter 38-22 Carbon Dioxide Underground Storage and North Dakota Administrative Code (NDAC) Chapter 43-05-01 Geologic Storage of Carbon Dioxide (continued)

Template Section	NDCC/NDAC Reference(s)	Requirement
Geologic Exhibits	NDAC 43-05-01-05 §1b(1)	(1) The name, description, and average depth of the storage reservoirs.
	NDAC 43-05-01-05 §1b(2)(k)	(k) Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone, including facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions.
	NDAC 43-05-01-05 §1b(2)	(2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following:
	NDAC 43-05-01-05 §1b(2)(g)	(g) Identification of all structural spill points or stratigraphic discontinuities controlling the isolation of stored carbon dioxide and associated fluids within the storage reservoir.
	NDAC 43-05-01-05 §1b(2)c	(c) Any regional or local faulting.
	NDAC 43-05-01-05 §1b(2)(j)	(j) The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone in the area of review, and a determination that they would not interfere with containment.

Continued . . .

Appendix B. Crosswalk of Template Sections and Citations from North Dakota Century Code (NDCC) Chapter 38-22 Carbon Dioxide Underground Storage and North Dakota Administrative Code (NDAC) Chapter 43-05-01 Geologic Storage of Carbon Dioxide (continued)

Template Section	NDCC/NDAC Reference(s)	Requirement
Geologic Exhibits	NDAC 43-05-01-05 §1b(2)(m)	(m) Information on the seismic history, including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment.
	NDAC 43-05-01-05 §1b(2)(n)	(n) Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the facility area.
	NDAC 43-05-01-05 §1b(2)(d)	(d) An isopach map of the storage reservoirs.
	NDAC 43-05-01-05 §1b(2)(e)	(e) An isopach map of the primary and any secondary containment barrier for the storage reservoir.
	NDAC 43-05-01-05 §1b(2)(f)	(f) A structure map of the top and base of the storage reservoirs.
	NDAC 43-05-01-05 §1b(2)(i)	(i) Structural and stratigraphic cross sections that describe the geologic conditions at the storage reservoir.
	NDAC 43-05-01-05 §1b(2)(h)	(h) Evaluation of the pressure front and the potential impact on underground sources of drinking water, if any.
	NDAC 43-05-01-05 §1b(2)(l)	(l) Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone. The confining zone must be free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream.
	NDAC 43-05-01-05 §1b(2)(o)	(o) Identify and characterize additional strata overlying the storage reservoir that will prevent vertical fluid movement, are free of transmissive faults or fractures, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.
Area of Review Exhibits	NDAC 43-05-01-05 §1j	j. An area of review and corrective action plan that meets the requirements pursuant to section 43-05-01-05.1.
	NDAC 43-05-01-05 §1b(3) *NDAC 43-05-01-05 §1a*	*NDAC 43-05-01-05 §1b(3)* (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following: *NDAC 43-05-01-05 §1a* a. A site map showing the boundaries of the storage reservoir and the location of all proposed wells, proposed cathodic protection boreholes, and surface facilities within the carbon dioxide storage facility area.

Continued . . .

Template Section	NDCC/NDAC Reference(s)	Requirement
Area of Review Exhibits	NDAC 43-05-01-05 §1b(2)(a)	(a) All wells, including water, oil, and natural gas exploration and development wells, and other manmade subsurface structures and activities, including coal mines, within the facility area and within one mile [1.61 kilometers] of its outside boundary.
	NDAC 43-05-01-05 §1c NDAC 43-05-01-05.1 §1a	*NDAC 43-05-01-05 §1c* c. The extent of the pore space that will be occupied by carbon dioxide as determined by utilizing all appropriate geologic and reservoir engineering information and reservoir analysis, which must include various computational *NDAC 43-05-01-05.1 §1a* a. The method for delineating the area of review, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;
	NDAC 43-05-01-05.1 §1b(1-4)	b. A description of: (1) The reevaluation date, not to exceed five years, at which time the storage operator shall reevaluate the area of review; (2) The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation date; (3) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and (4) How corrective action will be conducted to meet the requirements of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.
	NDAC 43-05-01-05 §1b(2)(b)	(b) All manmade surface structures that are intended for temporary or permanent human occupancy within the facility area and within one mile [1.61 kilometers] of its outside boundary;

Continued . . .

Template Section	NDCC/NDAC Reference(s)	Requirement
Area of Review Exhibits	NDAC 43-05-01-05 §1b(2)	(2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following:
	NDAC 43-05-01-05 §1b(3) NDAC 43-05-01-05.1 §2b	*NDAC 43-05-01-05 §1b(3)* (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following: *NDAC 43-05-01-05.1 §2b* b. Using methods approved by the commission, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone. Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and completion, and any additional information the commission may require.
	NDAC 43-05-01-05 §1b(3)(a-f)	(a) A determination that all abandoned wells have been plugged and all operating wells have been constructed in a manner that prevents the carbon dioxide or associated fluids from escaping from the storage reservoir. (b) A description of each well's type, construction, date drilled, location, depth, record of plugging, and completion. (c) Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all underground sources of drinking water, water wells, and springs within the area of review; their positions relative to the injection zone; and the direction of water movement, where known. (d) Maps and cross sections of the area of review. (e) A map of the area of review showing the number or name and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, state-approved or United States environmental protection agency-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features, including structures intended for human occupancy, state, county, or Indian country boundary lines, and roads. (f) A list of contacts, submitted to the commission, when the area of review extends across state jurisdiction boundary lines.

Continued . . .

Appendix B. Crosswalk of Template Sections and Citations from North Dakota Century Code (NDCC) Chapter 38-22 Carbon Dioxide Underground Storage and North Dakota Administrative Code (NDAC) Chapter 43-05-01 Geologic Storage of Carbon Dioxide (continued)

Template Section	NDCC/NDAC Reference(s)	Requirement
Required Plans	NDAC 43-05-01-05 §1k	k. The storage operator shall comply with the financial responsibility requirements pursuant to section 43-05-01-9.1.
	NDAC 43-05-01-05 §1d	d. An emergency and remedial response plan pursuant to section 43-05-01-13.
	NDAC 43-05-01-05 §1e	e. A detailed worker safety plan that addresses carbon dioxide safety training and safe working procedures at the storage facility pursuant to section 43-05-01-13.
	NDAC 43-05-01-05 §1f	f. A corrosion monitoring and prevention plan for all wells and surface facilities pursuant to section 43-05-01-15.
	NDAC 43-05-01-05 §1g	g. A leak detection and monitoring plan for all wells and surface facilities pursuant to section 43-05-01-14. The plan must: (1) Identify the potential for release to the atmosphere. (2) Identify potential degradation of ground water resources with particular emphasis on underground sources of drinking water. (3) Identify potential migration of carbon dioxide into any mineral zone in the facility area.
	NDAC 43-05-01-05 §1h	h. A leak detection and monitoring plan to monitor any movement of the carbon dioxide outside of the storage reservoir. This may include the collection of baseline information of carbon dioxide background concentrations in ground water, surface soils, and chemical composition of in situ waters within the facility area and the storage reservoir and within one mile [1.61 kilometers] of the facility area's outside boundary. Provisions in the plan will be dictated by the site characteristics as documented by materials submitted in support of the permit application but must: (1) Identify the potential for release to the atmosphere. (2) Identify potential degradation of ground water resources with particular emphasis on underground sources of drinking water. (3) Identify potential migration of carbon dioxide into any mineral zone in the facility area.
	NDAC 43-05-01-05 §1i	i. The proposed well casing and cementing program detailing compliance with section 43-05-01-09.
	NDAC 43-05-01-05 §1l	l. A testing and monitoring plan pursuant to section 43-05-01-11.4.
	NDAC 43-05-01-05 §1m	m. A plugging plan that meets requirements pursuant to section 43-05-01-11.5.
	NDAC 43-05-01-05 §1n	n. A postinjection site care and facility closure plan pursuant to section 43-05-01-19.

Continued . . .

Appendix B. Crosswalk of Template Sections and Citations from North Dakota Century Code (NDCC) Chapter 38-22 Carbon Dioxide Underground Storage and North Dakota Administrative Code (NDAC) Chapter 43-05-01 Geologic Storage of Carbon Dioxide

Template Section	NDCC/NDAC Reference(s)	Requirement
Injection Well and Storage Facility Operations	NDAC 43-05-01-05 §1b(4)	(4) The proposed calculated average and maximum daily injection rates, daily volume, and the total anticipated volume of the carbon dioxide stream using a method acceptable to and filed with the commission.
	NDAC 43-05-01-05 §1b(5)	(5) The proposed average and maximum bottom hole injection pressure to be utilized at the reservoir. The maximum allowed injection pressure, measured in pounds per square inch gauge, shall be approved by the commission and specified in the permit. In approving a maximum injection pressure limit, the commission shall consider the results of well tests and other studies that assess the risks of tensile failure and shear failure. The commission shall approve limits that, with a reasonable degree of certainty, will avoid initiating a new fracture or propagating an existing fracture in the confining zone or cause the movement of injection or formation fluids into an underground source of drinking water.
	NDAC 43-05-01-05 §1b(6)	(6) The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone and confining zone pursuant to section 43-05-01-11.2.
	NDAC 43-05-01-05 §1b(7)	(7) The proposed stimulation program, a description of stimulation fluids to be used, and a determination that stimulation will not interfere with containment.
	NDAC 43-05-01-05 §1b(8)	(8) The proposed procedure to outline steps necessary to conduct injection operations.

APPENDIX D

PUBLIC OUTREACH PACKAGE FOR CCS IN NORTH DAKOTA

PUBLIC OUTREACH PACKAGE FOR CARBON CAPTURE AND STORAGE IN NORTH DAKOTA

Integrated Carbon Capture and Storage for North Dakota Ethanol Production – Phase III
Task 5 – Deliverable D3

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EERC DISCLAIMER

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DOE DISCLAIMER

NDIC DISCLAIMER

(B) Assumes any liabilities with respect to the use of, or for damages resulting from the use of, any information, apparatus, method, or process disclosed in this report.

Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the North Dakota Industrial Commission. The views and opinions of authors expressed herein do not necessarily state or reflect those of the North Dakota Industrial Commission.

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EXECUTIVE SUMMARY

The Energy & Environmental Research Center (EERC), in partnership with Red Trail Energy, LLC (RTE), a North Dakota ethanol producer; the North Dakota Industrial Commission (NDIC); and the U.S. Department of Energy (DOE), is conducting a feasibility and implementation study for carbon capture and storage (CCS). The 64-million-gallon dry mill RTE ethanol facility, which emits an average 180,000 metric tons of CO_2 annually, is the subject of this case study to investigate secure, permanent, geologic CO_2 storage in western North Dakota. This document delineates the steps recommended for coordinating outreach events and the materials developed to serve as a guide for CCS efforts, particularly in rural communities.

RTE, the project developer and operator, was the public face for all events, such as commission meetings and community open houses. The outreach plan[1] developed in collaboration with RTE served as the basis for audience identification, engagement strategies, production and dissemination of informational materials, a system to track engagement activities and acquire feedback, and frequent progress assessment. Stakeholder groups targeted for engagement included landowners, residents, educators, and media within the RTE region as well as city, county, and state officials with authority over project and CCS activities.

Outreach engagement efforts in 2019 leveraged venues such as monthly city and county commission meetings, traditional and social media, and websites, in addition to facilitating community open houses and individual landowner communication to convey information about project-specific activities and overall RTE CCS status. All encounters included verbal information sharing on project activities and progress, providing the opportunity to ask questions, and supplying written materials and contact information as an invitation to learn more. A cache of project activity and CCS-focused fact sheets, posters, hands-on displays, and a project webpage (undeerc.org/RedTrailEnergy) was generated for meetings, informational packets, community open houses, landowner interactions, and other events such as media interviews. Materials summarizing the near-surface monitoring (groundwater and soil gas sampling) and characterization (geophysical/seismic survey) activities conducted were generated to inform and engage landowners and the community as well as support local public acceptance of North Dakota CCS. To date, feedback from the audiences has been generally neutral to positive, and overall, interactions have been constructive.

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[1] Leroux, K.M.; Klapperich, R.J.; Kalenze, N.S.; Jensen, M.D.; Daly, D.J.; Crocker, C.R.; Ayash, S.C.; Azzolina, N.A.; Crossland, J.L.; Doll, T.A.; Gorecki, C.D.; Stevens, B.G.; Botnen, B.W.; Foerster, C.L.; Schlasner, S.M.; Hamling, J.A.; Nakles, D.V.; Peck, W.D.; Glazewski, K.A.; Harju, J.A.; Piggott, B.D.; Vance, A.E. *Integrated Carbon Capture and Storage for North Dakota Ethanol Production – Phase II*; Final Report (Nov 1, 2017 – July 31, 2018) for North Dakota Industrial Commission Contract No. R-034-043; EERC Publication 2018-EERC-07-11; Energy & Environmental Research Center: Grand Forks, ND, July 2018.

Recommended practices for CCS outreach efforts include the following:

- Keep messages consistent across all target audiences.
- Share information with all stakeholders in advance of any field activities; the greater the visibility, the more broadly the information should be shared.
- Provide opportunities for audience questions.
- Anticipate questions and concerns, and have responses ready.
- Ensure all individuals engaged with project development understand anticipated concerns and how they are being addressed.
- Prepare press packets for every occasion.
- Develop good relationships with media.
- Consider multipurpose uses of outreach materials (provide resource conservation and message consistency).
- Treat every encounter as a chance to make a good impression.
- Provide regular updates on activity status and progress to landowners, local officials, and state regulators – it will be continually appreciated.

In general, messaging needs to help audiences understand how the technology can be implemented safely, and every encounter with the public—positive and negative—makes an impression. Encounters can occur anywhere, anytime, ranging from planned events (e.g., an open house) to casual conversation (e.g., local café, gas station, etc.). Given the rural close-knit communities near the RTE study region, encounters are shared among community members. Concerns to date have centered on human safety, groundwater and environmental protection, clarity and disclosure regarding the process, transparency as the process moves forward, and the trustworthiness of the project team and regulatory oversight. Outreach activities provide an opportunity for community members to learn about the project and be heard and reveal important concerns to be addressed as this first-of-its-kind facility in this region moves forward.

PUBLIC OUTREACH PACKAGE
FOR CARBON CAPTURE AND STORAGE IN NORTH DAKOTA – PHASE III

INTRODUCTION

Early, proactive public outreach with stakeholders is a pillar in the success of first-of-its-kind infrastructure development. The Energy & Environmental Research Center (EERC), in partnership with Red Trail Energy, LLC (RTE), a North Dakota ethanol producer; the North Dakota Industrial Commission (NDIC); and the U.S. Department of Energy (DOE), is conducting a feasibility and implementation study for carbon capture and storage (CCS) since 2016. Outreach is considered an integral part of project-related activities that have public contact or exposure.

This document covers the outreach conducted thus far to serve as a guide for other emerging CCS efforts, particularly in rural communities. The 64-million-gallon dry mill RTE ethanol facility, which emits an average 180,000 metric tons of CO_2 annually, is being used as a case study to investigate secure, permanent, geologic CO_2 storage in western North Dakota. The RTE facility is located approximately a half mile southeast of the town of Richardton in eastern Stark County, southwestern North Dakota (Figure 1).

The goal of project outreach is to engage stakeholders and create an environment that allows them to make informed community decisions regarding the project. Effective outreach plans create informed team members who can act as knowledgeable spokespeople for the project. Outreach is triggered by project-related activities that have public contact or exposure. This includes actions by the outreach team on behalf of the project, project management, the technical team, or partners. For the RTE CCS project, RTE acted as the public face for all events, with support from EERC technical and communications staff.

Outreach actions were geared to generate trust, a primary element in building good relationships, in the RTE CCS project among a variety of audiences through engagement, information sharing, and transparency. At the heart of these efforts was providing accurate information that responded to audience needs. The RTE CCS research effort required interaction with various stakeholders where value was provided through a dedicated and systematic outreach effort. Outreach and communication efforts were developed for research activities, coordinated with and supported by the field-based research teams, and provided informational and educational materials related to the proposed characterization and monitoring activities. Outreach activities included broad regional engagement and focused engagement with target audiences, including local and regional officials, landowners, and the community.

Outreach activities were a coordinated effort that encompassed 1) the project technical team (e.g., RTE, EERC, Trimeric Corporation), 2) partner outreach beyond the technical team (e.g., RTE employees and board, EERC employees, and other project partners), and 3) external outreach (e.g., local/regional officials, landowners, etc.).

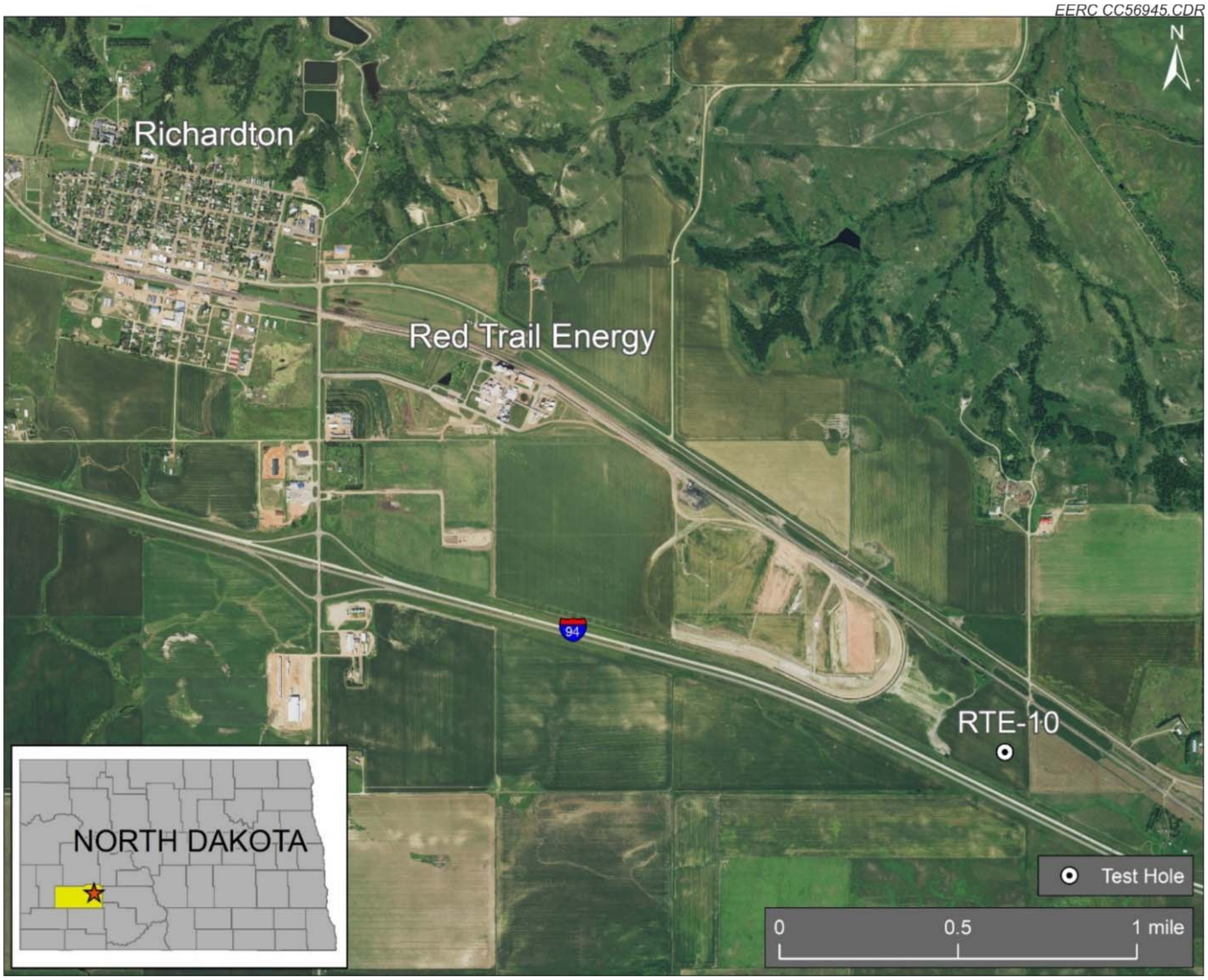

Figure 1. RTE ethanol facility located in Stark County, North Dakota, near Richardton and less than a mile north of Interstate Highway 94.

External outreach was triggered by project-related activities that had public contact or exposure. This included actions on behalf of the project by the outreach team, by project management, the technical team, or partners.

RTE CCS outreach was informed by prior expertise developed, in part, through the EERC's Plains CO_2 Reduction (PCOR) Partnership Program, part of the DOE's Regional Carbon Sequestration Partnerships (RCSP) Initiative (e.g., Daly and others, 2009; Daly and others 2016; Daly and others, 2018), and the RCSP Outreach Best Practice Manual (U.S. Department of Energy National Energy Technology Laboratory, 2017). These efforts built upon the collective outreach experience of the DOE RCSP Initiative, DOE Carbon Storage Assurance Facility Enterprise (CarbonSAFE) Initiative, outreach experiences for geologic CO_2 injection projects (e.g., Sacuta and others, 2016), and knowledge from commercial practices such as the models for evaluating public relations actions developed by Jim Macnamara (Macnamara, 2016).

OUTREACH PLAN

An outreach plan provides details on target audiences, messages, and engagement strategies for key relationships and materials to support project development. Effective outreach addresses five key questions, shown in Table1. The outreach plan answers these questions by defining goals, identifying audiences and engagement strategies, and laying out the time line for activities. This living document is frequently updated to respond to feedback and new information over the course of the project.

Table 1. Relating Outreach Plan Content to Key Project Story Questions

Outreach Development Questions		RTE CCS Outreach Plan
1	What are we trying to achieve and how do we best work together to achieve it?	• Goal, approach, and success measures • Partners' roles • Audiences • Implementation considerations and guidelines
2	What is our story?	• Outreach narrative, themes, and messages
3	How will audiences hear our story?	• Engagement strategies • Outreach tool kit
4	When do we need to tell the story?	• Outreach time line matched to technical time line and partner considerations
5	Who heard the story, and what do they think about it?	• Success measures/tracking/review and assessment

An outreach plan was developed in collaboration with RTE prior to initiating field activities (Leroux and others, 2018). The following is a summary of key elements.

Social Characterization

Social characterization was undertaken as a baseline assessment of stakeholders for the RTE CCS project to help define, quantify, and provide context to the social picture in the RTE area; develop the outreach approach; and identify elements influencing the social feasibility of CCS in the region. Research focused on Stark County within the context of the surrounding counties and state of North Dakota. Although natural energy resources (oil production and unmined coal) exist in western Stark County, the RTE CCS region comprises rural, agriculture-based communities.

Target Audiences

Several target audience categories were identified for engagement, including project partners, media, elected officials and regulators, the education community, the general public, technical (peer-to-peer) personnel, and environmental nongovernment organizations (NGOs). For the RTE CCS project, landowners are a critical subgroup under general public.

Project Narrative, Themes, and Messages

Generation of a single coherent story is essential for effective, informed team members to be knowledgeable spokespeople for the project. The story needs to be consistent whether presented as a one-sentence sound bite, a paragraph synopsis, or a project fact sheet. These messages provide a foundation for expansion and customization over the course of the project. Social characterization research, known concerns, and audience attitudes and perceptions were key inputs to message development. For example, the RTE CCS project one-sentence sound bite was derived as the following:

> *The RTE CCS effort is looking to address environmental concerns and strengthen the local economy by investigating the feasibility of and business case for secure, permanent, geologic storage of carbon dioxide from ethanol production.*

Tracking and Assessment Techniques

Tracking and assessment practices were based on existing and practiced EERC outreach protocols (e.g., Daly and others, 2009; Daly and others 2016; Daly and others, 2018). Outreach encounters, materials distribution, stories in the media, and webpage visits were tracked. Assessment involved evaluation of quantitative data and qualitative feedback from outreach encounters. To date, feedback from the audiences has been generally neutral to positive, and overall interactions have been constructive.

Engagement Strategies

The engagement strategies used to reach target audiences comprise three categories: 1) in-person, one-on-one conversations and small group presentations; 2) mass communications via mailings, traditional print and broadcast media, social media, and Internet interactions; and 3) indirect engagement through RTE, EERC and other project partner (e.g., NDIC, DOE) communication activities. Within each category, strategies were customized for specific audiences and the objective of the communication. In the case of the RTE CCS project, the open house and board meeting settings as well as interactions with governmental stakeholders facilitated one-on-one and small group engagement. Details on the engagement strategies are included in the audience relations sections under General Approach.

Materials Development

Outreach materials development involves preparing information necessary to understand the basics of CCS technologies and the RTE CCS project activities, particularly translating jargon and technical information into verbiage both familiar and relevant to the audience. These may include but are not limited to fact sheets (general project or activity-focused), posters, infographics, press releases, and bulleted talking points.

GENERAL APPROACH

As a project conducts publicly visible activities, such as a geophysical (seismic) survey acquisition or environmental sampling, outreach should become more interactive by matching research event schedules with the sequence of outreach audiences, strategies, activities, and materials development that must precede them. The RTE CCS project started a fast-paced outreach effort in February 2019 to introduce the project and the geophysical survey acquisition to key stakeholders. General nontechnical communication such as a press release(s), project fact sheet(s), and webpage(s) gave numerous opportunities for a wide audience to learn the basics of the project in a short time frame.

CCS Outreach Materials

Target audience and engagement strategy drove outreach materials development. Project materials were optimized through an iterative process of QA/QC reviews involving technical team members, project partners, and editing vetted through leadership teams. Content was developed from EERC technical materials, research and technical staff, social characterization, partner communications, and the experience of the outreach and graphic design teams. Example products developed to date for the RTE CCS effort are provided in Appendix A.

Local and Regional Official Relations

Two of the target audiences of public outreach for 2019 project activities were the Stark County Commission and Richardton City Commission, which includes the mayor of Richardton. As these boards meet monthly and accept presentations, the county and city commission meetings provide an ideal venue to engage local officials, share project information, learn about any potential approval(s) needed, gather feedback, and show goodwill toward the community and region. County and city administrative personnel attend the meetings, which allows each appearance to effectively inform and engage many county and city government departments, disseminating widespread information more effectively and efficiently into the communities.

RTE attended and presented at commission meetings in advance of and as follow-up to the major field activities of the project, including the geophysical survey, environmental sampling, geophysical survey results, and plans to submit a permit to drill application. Stark County and Richardton auditors were contacted 2 weeks in advance of published meeting dates (generally the first Tuesday and second Monday, respectively) to obtain a place on the meeting agenda. An overall provisional CCS time line was presented at each initial meeting. At each appearance, commissioners received an informational packet containing a project fact sheet and relevant activity-specific frequently asked questions (activities FAQs) fact sheets, presenter(s) business card(s), and, when applicable, an open house invitation and activity time line. Similar packets with a press release were prepared for media. In advance of each appearance, the outreach team developed talking points highlighting current status and future activities, relevant dates, pertinent results, and any critical information to be conveyed. Commissioners expressed appreciation for information in advance of activities.

The NDIC Department of Mineral Resources (DMR) Oil and Gas Division, a crucial stakeholder for the RTE CCS project, also received copies of the informational packets following each meeting. As the state regulatory entity overseeing all subsurface activity in North Dakota, DMR is the permitting authority for North Dakota's geologic CO_2 injection and storage program (North Dakota Industrial Commission, 2013) and is recognized as a "go-to source" by media for information of this type. Supplying DMR with up-to-date information regarding the project and public engagement 1) generated more efficient future meetings and 2) ensured DMR was aware of project progress and information in advance of potential media inquiries. Therefore, not only were good relations maintained, the interaction provided effective dissemination of project progress and information.

Landowner Relations

Positive relations with local landowners are a critical component to the success of any project field activities and, ultimately, the overall CCS effort. The RTE CCS project field activities conducted in 2019 involved testing on privately owned land, such as the geophysical survey and environmental sampling. In North Dakota, surface landowners also hold the pore space rights needed for permanent geologic CO_2 storage; therefore, building and maintaining positive relations is important for potential CCS implementation.

Direct contact proved the most effective and efficient engagement strategy. RTE hand-carried request-for-access letters to landowners when possible. Landowners living outside North Dakota were contacted via telephone as well as mail. This action facilitated the following:

- Face-to-face communication for trust- and relationship-building
- Opportunities for landowners to express concerns, receive immediate answers to questions, and provide feedback
- Timely responses to access requests

State regulations for geophysical survey acquisition require notification to landowners within a half-mile perimeter of the survey. Rural landowners were contacted via letter packet. City residents and other landowners were notified via public notice in local and regional newspapers (*Richardton Merchant* and *Dickinson Free Press*).

All content was developed for nontechnical audiences. Notification and cover letters were concise, with clear statement of purpose, easy-to-follow structure, commonly used verbiage, bullets and white space to encourage reading, invitation to learn more at the project website, and RTE contact information. In addition to material required by the geophysical survey permit (i.e., copies of the regulatory codes), every letter included the RTE CCS project fact sheet, relevant activity FAQs, and when applicable, a map and/or open house invitation. At the heart of landowner contact were:

- Facilitating communication.
- Keeping landowners informed.
- Dealing fairly and equitably with neighbors.
- Demonstrating trustworthiness, respect, and transparency.
- Showing that RTE is part of the local community.

Landowners received follow-up contact after field activities occurred—thank yous for cooperating with fieldwork, assessment of damages (required by the geophysical survey permit), and a report of the survey or sampling results. Landowners also received personal written and verbal invitation to the open houses (discussed further in the following section).

Community Relations

Maintaining the trust of the community is crucial to project and/or activity success. RTE is a visible member of the Richardton community given its location between the Interstate 94 exit and the City of Richardton (Figure 1). The RTE ethanol facility depends on local farmers for its corn feedstock. Thus showing transparency and providing opportunities for community information-sharing is vital to RTE's sustainability and the CCS effort.

The community was defined mainly as Richardton area residents. Nearby communities were also included in outreach efforts (via print and broadcast media) because of the rural nature of the area:

- Richardton, 557 population (U.S. Census Bureau, 2018)
- Dickinson (Stark County seat, 26 miles west of Richardton), 22,739 population
- Hebron (18 miles east of Richardton), 675 population

The defined community was invited (in addition to landowners) to attend two RTE CCS project open houses, in March 2019 and December 2019, providing general project information, activity status, and results. The geophysical survey conducted in March 2019 was the first fieldwork event for the CCS effort, presenting an opportunity to create a positive tone for future community interaction, transparency, and trust. The survey was a highly visible activity covering an ~8-square-mile area directly east of Richardton, with several field crews on ATVs and vibroseis trucks operating over several weeks, and community notification requirements (discussed in the previous section). RTE obtained a permit to drill on December 2, 2019, to drill a stratigraphic test hole in early 2020, providing an excellent opportunity to engage with the community for a second open house. This event focused on results from the geophysical survey, information regarding the upcoming drilling effort, and overall project outlook moving forward. Appendix A contains materials related to the survey and drilling.

The open houses were advertised in regional newspapers, flyers hung around local businesses in Richardton and Hebron, a digital sign at city limits, and word of mouth. Community members within a half-mile of the geophysical survey boundaries received an invitation in their notification letters. Project information and an open house invitation were shared with the school district office and letters to teachers as 1) the path of the geophysical survey vehicles took fieldwork within sight of the school and 2) another means of getting information into the public should teachers decide to share information with their students. The procedure developed for coordinating and executing the open houses is provided in Appendix B.

Media Relations

Developing relationships with local journalists and those within the energy "beat" is crucial to ensure that accurate information about the project gets to the public. Technical projects can be difficult to portray accurately in the media because they cannot be easily boiled down to a sound bite or short article. The communications and outreach team worked with all project partners to develop key messages about the RTE CCS project. Those messages were used in developing news releases and communicating with local media (including both television and radio interviews). Each journalist assigned to reporting on the project has different needs in understanding the project based on their goals and experience. For example, an energy reporter for a trade publication may be well-versed in writing about CCS. A journalist for a general publication covering diverse topics may need more context to aid in understanding the topic. Proactively developing relationships with local journalists establishes a communication channel for media to get accurate information from the project team.

The communications team sought opportunities to be proactive in providing information and engage with area journalists. A general rule of thumb in media relations is that if they do not receive the information from the project contact, they will find it from somewhere else and it may be inaccurate or outdated. In developing relationships with journalists, the project benefits most from a communications team that is helpful to media contacts in accomplishing their jobs.

Establishing relationships with influential media in the area facilitates dissemination of accurate information. Having relationships with media reduces the likelihood of misinformation because the reporters come to the source for clarification on key facts. In addition, having those relationships establishes a communication channel to address misinformation as soon as possible. Print and broadcast media in the project area included local, county-size, and statewide components.

Print media targeted for communications included the following:

- *Richardton Merchant*, 983 biweekly circulation
- *Hebron Herald*, 764 weekly circulation
- *Dickinson Free Press*, 4970 daily circulation
- *Bismarck Tribune*, 16,861 daily circulation

Broadcast media included the following:

- Bismarck TV station KFYR (market share unavailable)
- Radio station 1100AM The Flag's weekly radio show, "Energy Matters," with approximately 45,000 weekly listeners (broadcast and live streaming)

Both local newspapers, the *Hebron Herald* and *Richardton Merchant*, run out of the same office. The editor was willing to cover RTE CCS open house events and fieldwork in the publications. Because of the small staff, a rapport was easy to establish, allowing accurate information to be provided during story/article development.

The RTE CCS project was featured on the 1100 AM radio show “Energy Matters” three times during the reporting period. The show is a source of energy-related information statewide and has approximately 45,000 weekly listeners. The host of the show is well-versed in energy topics and skillfully asks questions that help get information out to the show’s audience, which is a wide array of statewide listeners, from general public to experts in energy. Statewide exposure about the project elevates its importance and helps connect it to other CCS projects across North Dakota.

RECOMMENDATIONS

Every outreach activity should be treated as an opportunity to assess and improve. The EERC continues to establish and strengthen connections with media outlets as an objective “go-to source” for project-specific questions as well as relevant geology and CCS concepts. In addition, media packets are now generated for each commission meeting, on hand at the RTE main office, and given to DMR.

Personal contact and communication lead to measurable benefits. Direct landowner interaction and communication by RTE led to greater participation at the open houses. About 30 community visitors attended each event, expressing positivity and curiosity regarding the overall RTE CCS effort, creating positive buzz about the project, and building community rapport and trust.

Advanced planning and teamwork are essential. EERC field crews for the geophysical survey and environmental sampling activities were briefed on the RTE CCS project and carried copies of the project fact sheet and activity FAQs to share with individuals curious about the activity, the RTE CCS project, or CCS in general. EERC field crews drove and worked from easily identifiable vehicles, were polite and friendly, were respectful of private property, and were conspicuous consumers of the local economy (e.g., took meals in the local café).

Sharing project and activity information, communicating to convey understanding, demonstrating transparency, and showing respect are critical elements to building the trust needed for community support of a CCS effort. Public perception is an aspect that can make or break any first-of-a-kind effort, regardless of how technically and environmentally sound. Key recommendations for the RTE CCS outreach efforts included the following:

- Keep messages consistent across all target audiences.
- Share information with all stakeholders in advance of any field activities; the greater the visibility, the more broadly the information should be shared.
- Provide opportunities for audience questions.
- Anticipate questions and how they can be addressed.
- Ensure all individuals engaged with project development understand anticipated concerns and how they are being addressed.
- Prepare press packets for every occasion.
- Develop good relationships with media.

- Consider multipurpose uses of outreach materials (provide resource conservation and message consistency).
- Treat every encounter as a chance to make a good impression.
- Provide regular updates on activity status and progress to landowners, local officials, and state regulators – it will be continually appreciated.

Messaging needs to help audiences understand how the technology can be implemented safely, and every encounter with the public—positive and negative—makes an impression. Encounters can occur anywhere anytime ranging from planned events (e.g., an open house) to casual conversation (e.g., local café, gas station, etc.). Given the rural close-knit communities near the RTE study region, all encounters will likely be shared among community members. Concerns to date have centered on human safety, groundwater and environmental protection, clarity and full disclosure regarding the process, transparency as the process moves forward, and the trustworthiness of the project team and regulatory oversight. Providing opportunities for community members to feel heard not only generates positive attitudes toward the project team, but also reveals important concerns to be discussed as this first-of-its-kind facility in this region moves forward.

FUTURE OUTREACH EFFORTS

Public outreach activities will continue throughout CCS implementation, particularly any time a project-related activity has potential for public contact or exposure. Examples of subsequent RTE CCS efforts may include (certainly not limited to) the following:

- Permitting and drilling a stratigraphic test hole
- North Dakota CO_2 storage facility permit application (approval process includes a public hearing)
- Construction of a CO_2 capture facility
- Drilling and construction of the CO_2 injection and monitoring wells
- Ribbon cutting on the CCS facilities (i.e., start of operations)
- Monitoring activities for permit compliance such as environmental sampling, geophysical surveys, etc.

Increasing educational outreach would help teachers educate the future generation of decision-makers to engage in problem-solving in their backyard, in their state, in their region, to go beyond the focus on problem identification. Informal education opportunities using displays and demonstrations at county and state fairs, career fairs, STEM Night at the baseball game, etc., could be effective at informing and engaging learners of all ages.

A documentary film showcasing how CCS research culminates into a commercial facility could bring value to the local economy and North Dakota. When North Dakota's lower-carbon ethanol is sold, the broader reach of video brings the story to a larger audience and provides context to help national viewers understand its significance.

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APPENDIX A

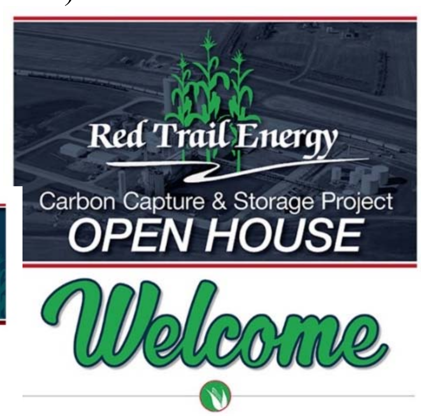
RED TRAIL ENERGY CCS PROJECT 2019 OUTREACH MATERIALS

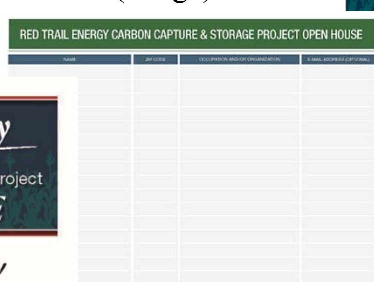
RED TRAIL ENERGY CCS PROJECT 2019 OUTREACH MATERIALS

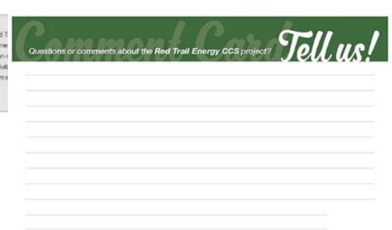
This document summarizes the content of Appendix A. The full-scale document is available by request from the North Dakota Industrial Commission Renewable Energy Program (http://www.nd.gov/ndic/renew-infopage.htm).

FACT SHEETS
CCS Project Fact Sheet, Red Trail Energy CCS Project
Activity FAQs, Completed Geophysical Survey near Richardton, N.D.
Activity FAQs, Water and Soil Gas Sampling near Richardton, North Dakota
Activity FAQs, Geology Study – Drilling Down at Red Trail Energy
Results of the March 2019 Geophysical Survey near Richardton, North Dakota

RTE CCS PROJECT OPEN HOUSE ADVERTISING AND COMMUNICATION MATERIALS
March 6, 2019 Open House Invitation (graphic also used for newspaper advertisement)
December 11, 2019 Open House Invitation (graphic also used for newspaper advertisement)
Richardton Digital Sign
Landowner – Geophysical Survey Participant (thank you and invitation)
Nearby Landowners, Commissioners, Legislators Invitation
Educators Invitation
Sign-In Sheet
Comment Card
Welcome
Post-Event Press Release (March 2019)
Post-Event Press Release (December 2019)
Post-Event Thank You Card (image)

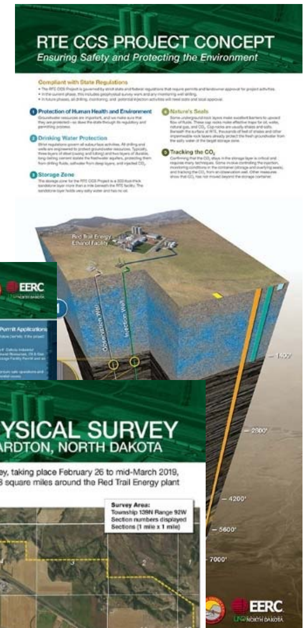


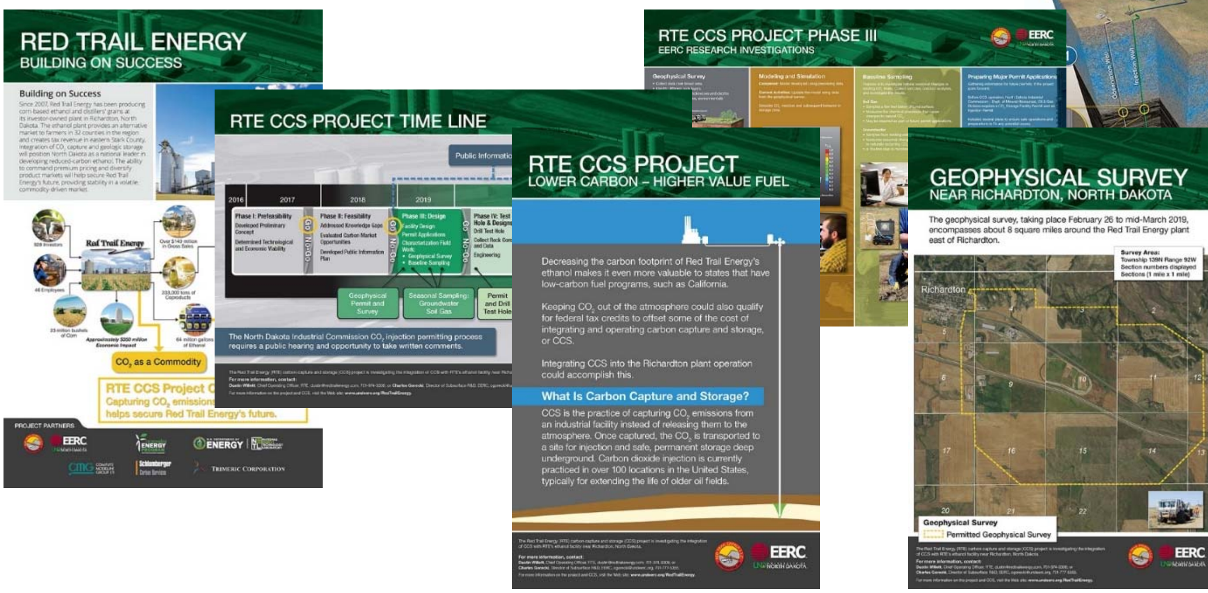




RTE CCS PROJECT OPEN HOUSE POSTERS – MARCH

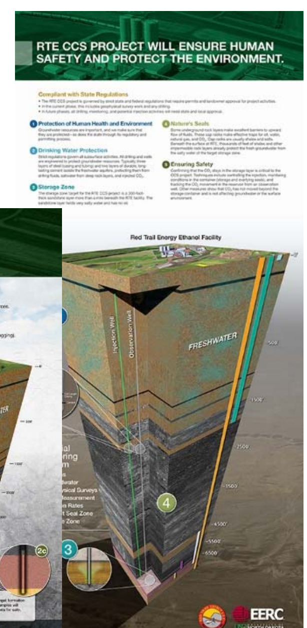
RTE Building on Success
RTE CCS Project Time Line
RTE CCS Project: Lower Carbon – Higher Value Fuel
RTE CCS Project Concept: Ensuring Safety and Protecting the Environment
RTE CCS Project Phase III: EERC Research Investigations
Geophysical Survey Near Richardton, North Dakota





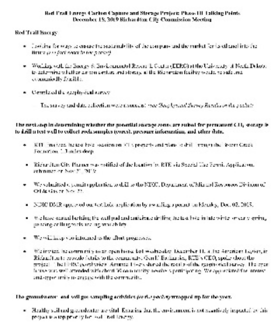
RTE CCS PROJECT OPEN HOUSE POSTER – DECEMBER

Capturing CO_2 Emissions Helps Secure Red Trail Energy's Future
RTE CCS Project Moves to Phase IV
Geophysical Survey and Environmental Sampling Pave the Way to the Next Phase
Detailed Plans and Process Ensure Human Safety and Protect the Environment
Drilling for Data: Steps for a Test Hole
RTE CCS Project Will Ensure Human Safety and Protect the Environment



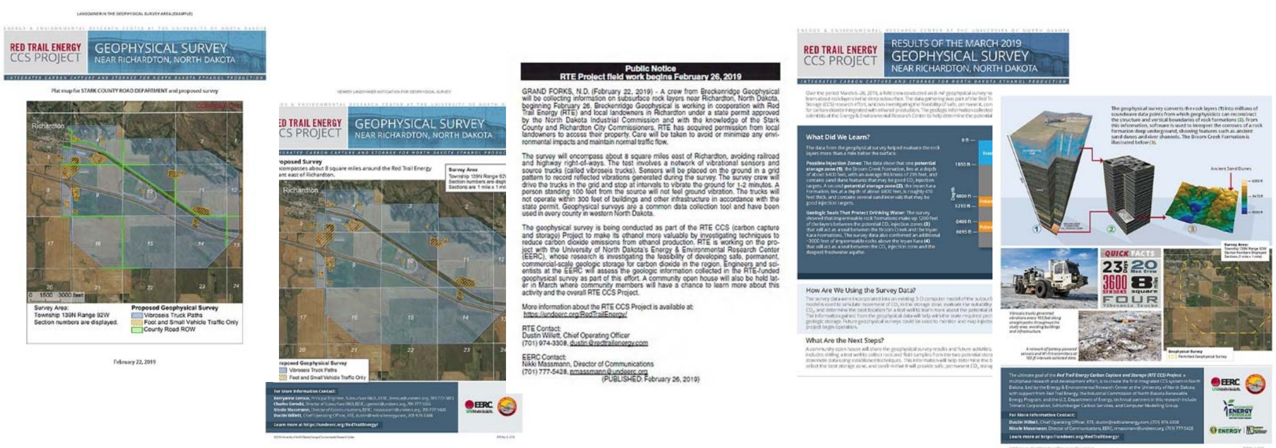
RED TRAIL ENERGY CARBON CAPTURE AND STORAGE PROJECT: PHASE III COMMISSION MEETING TALKING POINTS

Stark County February 5, 2019
Stark County April 2, 2019
Stark County October 1, 2019
Stark County December 3, 2019
Richardton City December 18, 2019



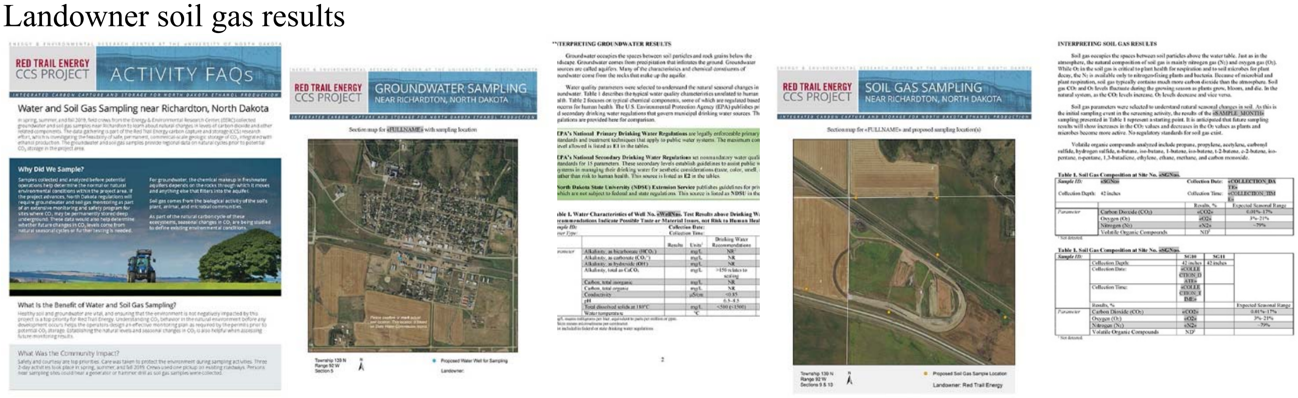
GEOPHYSICAL SURVEY DOCUMENTS

Landowner in the Geophysical Survey Area Notification Packet
Nearby Landowner Notification for the Geophysical Survey Packet
Geophysical Survey Sample Q&A for Landowner Contact February 2019
Public Notice RTE Project Field Work Begins February 26, 2019
RTE CCS Project Continues Field Work Through 2019 (news release)
Results of Geophysical Survey – March 2019: landowner survey results with cover letter
March 2019 RTE Geophysical Survey Results Talking Points – August 14, 2019



GROUNDWATER AND SOIL GAS SAMPLING DOCUMENTS

Landowner access request packet for groundwater sampling
Landowner access request packet for soil gas sampling
RTE CCS Project Phase III Talking Points May 2019 Permission for Sampling Landowner Contract
Landowner groundwater results
Landowner soil gas results



MEDIA INQUIRIES

EERC and Red Trail Energy Continue to Reduce Carbon Dioxide Emissions

APPENDIX B

OPEN HOUSE COMPONENTS AND PLANNER

OPEN HOUSE COMPONENTS AND PLANNER

Open House Planner with Time Line in Relation to Planned Event Date

Time Line	Action	Instruction	Outcome/Product/Notes
6–8 weeks prior	Request for open house assistance		Requested by client leadership or suggested by the EERC before a new stage of project begins
6–8 weeks prior	Establish open house working team	• Consisting of project lead, researchers, outreach and communications team members, and an administrative assistant	• EERC: Project Manager, Outreach Lead, Geophysicist Lead, Regulatory Lead, Geoscientist Lead, AA, Communications Director, Communications Coordinator, Photographer • Client: Provided messaging assistance and approval as needed
Weekly thereafter	Meet as necessary to discuss details and deliver updates to team	• Choose location, date, and time • Consider the availability of spaces in closest town, scheduling conflicts, and time zones	*Examples:* • Wednesday, December 11, 2019, 6:00–8:00 p.m. • Richardton American Legion • Called school district, checked sports schedules, holidays, and community meeting schedules
6 weeks prior	Create message and engagement strategies for intended audience	• Evaluate the current project stage and next stage-progress to determine the general public concerns that should be addressed • Create posters that are helpful in gaining a deeper understanding of the project without explanation from an expert	• Discussed testing results, next steps in project, and common public concerns • Existing EERC graphics and language are considered for current utility and modified if needed with assistance from internal members • Graphics creates or revises poster files with approved text and graphical elements
3 weeks prior	Create invitations and invitation lists, and distribute	• Landowners, local and state officials, town and regional community, dependent on who is impacted most by new stage of project Mail, newspaper listings, digital signage (where available), social media	• Begin submitting to media sources at least 3 weeks before event to guarantee best visibility to target audience • *Examples: Richardton Merchant, Hebron Herald, Dickinson Press, and Bismarck Tribune* were chosen for their reach to the target audience • Distribution frequencies range from daily to biweekly, and submission dates vary for each *Examples:* Digital sign in Richardton is run by Suzy from Suzy’s Stash in Richardton – appendixes show submission instructions and display capabilities

Continued . . .

Open House Planner with Time Line in Relation to Planned Event Date (continued)

Time Line	Action	Instruction	Outcome/Product/Notes
3 weeks prior	Create invitations and invitation lists, and distribute	• Landowners, local and state officials, town and regional community, dependent on who is impacted most by new stage of project • Mail, newspaper listings, digital signage (where available), social media	• Begin submitting to media sources at least 3 weeks before event to guarantee best visibility to target audience • *Examples: Richardton Merchant, Hebron Herald, Dickinson Press, and Bismarck Tribune* were chosen for their reach to the target audience • Distribution frequencies range from daily to biweekly and submission dates vary for each • *Examples:* Digital sign in Richardton is run by Suzy from Suzy's Stash in Richardton – appendices show submission instructions and display capabilities
Week of Event	Prepare all materials and to travel to open house	• Printed materials including posters, comment cards, sign-in sheets, handouts • Food, beverages, and related items	*Examples:* • December 2019 open house required six posters, easels for each, and supporting handouts • Assorted bars and apple cider, including warmer, were purchased/rented through UND Campus Catering
Day of Event	Execute open house	• Follow time line for scheduled presentations, circulating to speak with researchers, final questions • Discuss event outcomes with internal attendees and client leadership to determine successfulness and follow-up needs	
1–2 weeks post	Track and record engagement through sign-in sheets, news items, etc.	• Number of attendees, overall attitude of attendees, questions asked, any concerns to address moving forward	All items should be recorded in TruServe for best reporting on outreach efforts over time
1–2 weeks post	Write and share postevent news release	• News release has historically been written at the EERC and sent to client leadership for quotes and approvals • Share on the EERC Solutions blog and sent as a news release to North Dakota news outlets	Increases visibility/reach and support of client and efforts to inform the community about project events
As needed	Report on open house to necessary parties	• Collect utilized materials for demonstration of efforts • Compile responses to determine success level and necessary next-stage efforts	Dependent on project specifications

*All final actions/decisions require approval from client.